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Draft Environmental Impact Statement

Conversion to Coal
Holyoke Water Power Company
Mt. Tom Generating Station
Unit 1
Holyoke, Hampden County, Massachusetts

October 1982

U.S. Department of Energy
Economic Regulatory Administration
Office of Fuels Programs

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U.S. Department of Energy
Economic Regulatory Administration
Office of Fuels Programs
Washington, D.C. 20585

Responsible Agency:	U.S. Department of Energy Economic Regulatory Administration Office of Fuels Programs Fuels Conversion Division
Title of Proposed Action:	Issuance of Notice of Effectiveness for Prohibition Order to Mt. Tom Generating Station Unit 1, Holyoke Massachusetts
Designation:	Draft Environmental Impact Statement
Further Information:	Ms. Anne Randolph Office of Fuels Programs Fuels Conversion Division Economic Regulatory Administration 1000 Independence Ave., S.W. Room GA-093 Washington, D.C. 20585
Abstract:	This draft environmental impact statement (DEIS) assesses the potential impacts associated with the proposed issuance of a Notice of Effectiveness which would finalize the prohibition order for Unit 1 of the Mt. Tom generating station, located in Holyoke, Massachusetts. If finalized, the prohibition order would prohibit the utility from using petroleum products as a primary energy source in the affected unit; the utility's response to the orders has been to return its Unit 1 to burning low-sulfur coal. Major issues of environmental concern relating to the conversion have been determined through the public scoping process and through discussion with other concerned agencies, and were found to include air and water quality, noise, encroachment on the 100-year floodplain; and waste storage and disposal. These issues, as well as reasonable alternatives in the areas of plant conversion options, fuel type, air and water pollution control, ash disposal, and transportation, are discussed in the EIS.
Closing Date for Comments:	Comments should be sent to Anne Randolph at the address noted above. The closing date for comments is 45 days after Federal Register publication of a Notice of Availability by EPA.

SUMMARY

INTRODUCTION

The Mt. Tom generating station is in Holyoke, Massachusetts, on the west bank of the Connecticut River. The plant, which was completed in 1960, was designed to burn coal as the major energy source. The unit was converted to oil firing in 1970; it continued to burn oil from that date until December 1981 except for a short period during the oil embargo of 1973-1974 when it was switched back to burning coal.

On June 30, 1977, the plant was issued a prohibition order by the Department of Energy (DOE) under the Energy Supply and Environmental Coordination Act (ESECA). If finalized by a Notice of Effectiveness (NOE), this order would prohibit the plant from utilizing petroleum products as a major energy source. Under terms of a Memorandum of Understanding (MOU) with the State of Massachusetts and a Delayed Compliance Order (DCO) issued by the U.S. Environmental Protection Agency (EPA) Region I, Holyoke Water Power Company (HWP), owner of the facility, returned the plant to burning a low-sulfur coal in December 1981. HWP is a wholly owned subsidiary of Northeast Utilities System (NU). Northeast Utilities Service Company (NUSCO) has been acting as agent for HWP with regard to all activities required for conversion of the station to coal burning.

This Draft Environmental Impact Statement (EIS) has been prepared by the Division of Fuels Conversion of the Economic Regulatory Administration of DOE as part of DOE's responsibility under the National Environmental Policy Act (NEPA). DOE has determined that issuance of an NOE is a major Federal action significantly affecting the quality of the human environment and that an EIS is required.

Major issues relating to reconversion of the plant to coal have been determined through the public scoping process and through discussion with other concerned agencies, especially EPA Region I; the Massachusetts Department of Environmental Quality Engineering (DEQE); and the Massachusetts Executive Office of Environmental Affairs. Issues of concern include: air quality, water quality, noise, waste storage and disposal, and encroachment on the 100-year floodplain. These issues, as well as reasonable alternatives to the utility's reconversion to low-sulfur coal as the major energy source, are discussed in this EIS.

PURPOSE OF AND NEED FOR ACTION

The oil embargo of 1973-1974 brought into sharp focus the Nation's dependence on imported oil. ESECA was passed by Congress in 1974 in response to the embargo. One of DOE's responsibilities under ESECA was to identify existing power plants that could most readily convert from use of petroleum products to another fuel. A group of facilities selected included those that had been originally designed to burn coal, but that had subsequently switched to oil or gas. The Mt. Tom generating station is one of these powerplants. Use of low-sulfur coal at this plant may save about 1.5 million barrels of oil per year over the remaining 20-year life of the plant when the facility is operating at the expected 80 percent capacity. This reduction in oil usage will contribute to lessening the country's dependence on imported oil.

ALTERNATIVES

As noted in the Council on Environmental Quality's (CEQ) regulations on preparation of environmental impact statements, the analysis of alternatives is the heart of an EIS. This EIS includes discussions of reasonable alternatives to the proposed action, which is issuance of an NOE. Issues of concern, as identified in the scoping process and in discussions with other agencies, are stressed.

DOE's alternatives are restricted to two: (1) to issue the NOE, or (2) to not issue the NOE. Under either of these alternatives, the utility has several options as noted in the following paragraphs and as discussed in the text of this EIS. The utility's preferred option has been to convert the Mt. Tom generating station to burning low-sulfur coal. To expedite such a conversion, the utility entered into an agreement with the state regarding conditions for the conversion and conducted negotiations with EPA Region I to the same end. (See Low-sulfur Coal Conversion alternative discussed below.)

Alternatives include: no action, under which the utility has several options including return to burning oil; the utility's preferred plan - reconversion to low-sulfur coal; use of alternative fuels; alternative ash disposal methods; alternative transportation methods; and alternative plant configurations.

No Action

Under the no action alternative, the utility could, among many options, elect to return to burning oil, could continue the conversion to coal, or could retire the plant.

Low-sulfur Conversion

Under the utility's response to the prohibition order, the Mt. Tom generating station returned to burning a low-sulfur coal (1.5 percent sulfur) in its one 145 megawatt unit. This will require about 384,000 tons of coal per year and could save approximately 1.5 million barrels of imported oil per year. It should be noted that from the mid 1970s to 1980 the plant operated as an intermediate load plant, burning only about 0.9 million barrels of oil per year while operating at less than the presently expected capacity. The coal is brought to the site by 70-car unit trains, one train about every 5 days.

To help accomplish the conversion, the utility entered into a Memorandum of Understanding (MOU) with the Commonwealth of Massachusetts. Under the MOU, the Mt. Tom generating station began to burn low-sulfur coal in December 1981. As part of the requirements for the conversion, EPA Region I determined that a Delayed Compliance Order (DCO) could be issued for the facility and issued such an order on November 24, 1981, allowing the station to exceed currently permitted limits for particulate matter (PM) emissions for the period the DCO is in force (not to exceed 27 months; or until February 15, 1984). These increased emissions must maintain primary National Ambient Air Quality Standards (NAAQS) and must be reduced to within SIP limits as soon as a new precipitator can be purchased and installed.

A second critical element of the utility's conversion plan is implementation of an Oil Conservation Adjustment (OCA) to finance the conversion. Under Massachusetts law, the OCA permits the utility to establish the cost of oil and the cost of coal at the time of conversion and to reserve two-thirds of the cost differential for paying the costs of the conversion. The remaining one-third difference in cost is to be passed on to the ratepayer immediately. Once the conversion is paid for, the entire fuel cost savings will accrue to the ratepayers.

Initial construction required repair and upgrading of existing coal handling and burning equipment and reactivation of ash and wastewater ponds and coal storage facilities.

Under the MOU and DCO, the present electrostatic precipitator has been overhauled to permit initial coal burning with PM emissions of 0.48 lb per million Btu. This quantity is to be reduced to 0.35 lb/10^6 Btu about 8 months after initial coal burning (by means of upgrading the present precipitator) and reduced to below oil fired emission rates when a new electrostatic precipitator is completed and installed some time prior to February 15, 1984. At that time PM emissions will be reduced to 0.08 lb/10^6 Btu; this will mark the end of the DCO period.

Also under the MOU, HWP committed to modifications to the coal thawing equipment and to the car shaker facility to reduce noise impacts to nearby residences.

A detailed hydrogeologic study of the Mt. Tom site was completed in June 1981 by a consultant to the utility. This study characterized the hydrogeologic setting and identified the potential for degradation of water quality resulting from the storage and disposal of coal and ash at the site. As a result of the first phase of the study, the coal pile and coal runoff areas have been lined, and coal leachate and runoff are collected. Further mitigative measures will be required should monthly monitoring show a degradation of ground or surface water quality from coal storage or ash disposal.

Because much of the plant area lies within the 100-year floodplain of the Connecticut River there is concern over the use of onsite land, particularly for ash storage. As a result HWP has committed to providing compensatory storage for 300 acre-feet of flood waters during the 100-year storm event and to investigate alternative methods of ash disposal. Use of the onsite fly ash basin is permitted through March 1983.

Fuels

Other fuels considered as potential major energy sources include high-sulfur coal, refuse-derived fuel (RDF), and wood/wood chips. None of these is considered viable: (1) high-sulfur coal would require use of a flue gas desulfurization (FGD) system, which would require construction of additional facilities, additional transportation, and additional storage acreages, and would introduce additional environmental concerns; and (2) neither RDF nor wood is available in sufficient quantities to make these reliable energy sources for the plant at this time.

Ash Disposal

The utility's plan initially, is to store ash onsite in reactivated ash storage basins and as landfill. Following discussions with DEQE on use of the floodplain, two alternative methods of disposal have been evaluated: sale and offsite disposal. Sale of fly ash (which will account for 80 percent of the ash produced) is dependent on the characteristics of the ash, which are being determined following initial coal burning. If the ash has characteristics similar to those projected by the utility, a market does apparently exist. Offsite disposal, if required by the state, will necessitate use of existing landfills, which are rapidly being filled, or acquisition of environmentally acceptable land on which to develop a landfill site. Either sale or offsite disposal will require additional vehicular traffic and the installation of a dry fly ash collection system.

Transportation

Other methods of transportation of coal to the site include barge and coal slurry pipeline. Since the plant site is not adjacent to waters navigable by barges, this alternative is not viable. No coal slurry pipelines are available or planned for construction in this area during the life of the plant.

Other Alternatives

Because the plant is an existing electric generating station, and because it was originally designed to burn coal, most facilities were in place prior to modification to return to coal burning. Certain facilities might be relocated onsite to remove them from the 100-year floodplain.

A rotary car dumper could be installed as an alternative to the car shaker. This would provide for faster unloading of coal cars and some reduction in noise, but at considerable additional cost.

ENVIRONMENTAL IMPACTS

As noted previously, major issues of concern are air and water quality, use of the floodplain, ash disposal, noise, and disruption of archaeological sites. Impacts to regional or site geology, aquatic or terrestrial biota, transportation, housing, labor market, or other socioeconomic factors are expected to be minimal.

Air Quality

Conversion to coal under the MOU and the DCO will increase SO_2 emissions over the short-term (24-hour average or shorter), but not for the 30-day averaging period. NO_2 emissions are estimated to increase by 1,500 tons per year. Neither of the changes will produce a significant impact when compared to emissions of SO_2 and NO_2 on the regional scale. PM emissions will increase nearly five fold (from 16.7 to 82.9 grams/second) over the first 8 months of coal burning. During the remainder of the DCO (about 17 months) they will be reduced to 3.6 times the rate under oil burning. Following installation of the new precipitator, they will be reduced to about 83 percent of pre-conversion emissions (all figures are while the plant is operating at 80 percent capacity).

Increases in fugitive dust can be expected during construction activities and after conversion as a result of ash- and coal-handling activities. Mitigative measures to reduce impacts of increased dust include wetting down of construction roads and uncovered slopes and ponds, enclosing conveyors, wetting down of the coal pile, and wet sluicing of ash (initially; later, fly ash will be collected dry.

Water Quality

The Mt. Tom generating station currently has ten waste streams which are discharged under an NPDES permit issued in November 1981. Conversion to coal required modification of the permit for the fly ash and bottom ash discharges. Under present plans the ash and wastewater ponds will not be lined, but the coal pile and coal pile runoff areas have been lined and any discharge from those areas will be routed through the wastewater treatment system.

A detailed hydrogeologic study was conducted at the plant site prior to the conversion. This study has revealed the existence of a plume of contaminated water extending to the Connecticut River from the old coal pile area; the identification of this plume was the basis for the determination to line the coal pile and coal pile runoff areas. A second area of minor contamination was also noted in the southern part of the property in the vicinity of the old fly ash ponds, but it is believed this will be sufficiently diluted by ground water flow, soil attenuation, and mixing with river water that there will be no measurable change in quality of Connecticut River water. Under the MOU, a year of monitoring following conversion was anticipated; in discussions with DEQE, the utility has agreed to conduct a long-term ground water monitoring program to identify and correct any significant contamination.

Floodplains

About 77 acres of the 89-acre site are within the 100-year floodplain of the Connecticut River. Because the equipment and facilities are already in place, and because the wastewater and ash ponds were already in existence prior to the coal conversion there appears to be no reasonable alternative to use of 103 acre-feet of flood storage during the initial conversion period. To compensate for this, NU has agreed to reserve 300 acre-feet of storage during the 100-year flood at the Northfield Mountain pumped storage facility, some 30 miles upstream from the Mt. Tom generating station. The utility is also seeking a market for fly ash and, if this is not available, is committed to acquiring an offsite disposal site. Use of onsite land for ash storage for the life of the plant, if it were permitted, would require an additional 44 acre-feet of floodplain storage (over the 103 acre-feet required by existing modifications).

Ash Disposal

Ash disposal onsite over the life of the plant would encroach on 44 acre-feet of flood storage and would require removal of some 15 acres of prime farmland for the life of the project. Sale of ash would increase traffic slightly in the plant vicinity, and use of an offsite disposal area would involve increased costs, increased transportation, and probable other impacts which would have to be assessed once a site was selected.

Noise

Experience during previous periods of coal burning indicates that increased noise levels were noticeable at residences across the river. HWP has made modifications to the shaker house, including lining portions of the building and erecting a sound barrier adjacent to the structure. A new electric thawing system is being installed which is quieter than the previously used system. Use of bulldozers and conveyors to move coal onsite and the coal crusher may increase noise levels by 5 to 10 dB, but noise levels will be below 65 dB. Unloading of coal will be restricted to certain hours as required by the MOU.

Archaeological Sites

A re-review of information on archaeological sites on the property by the State Historical Commission Staff indicated the presence of two sites on the property. A preliminary survey conducted by a consultant to the utility revealed the presence of the sites. Most anticipated construction activity had been completed (the fly ash basin, the grub storage area, and the borrow pit) prior to the re-analysis by the Historical Commission. The utility will not conduct further construction in the area of the sites without a detailed archaeological investigation or consultation with the Massachusetts Historical Commission.

UNRESOLVED ISSUES

Issues remaining unresolved include: (1) encroachment on the 100-year floodplain of the Connecticut River; (2) possible future need to line onsite ponds; (3) need for additional archaeological studies; (4)disposal of ash by sale or at an offsite location; and (5) extent of possible future contamination of surface and ground water.

CONCLUSIONS

Conversion of the Mt. Tom generating station to coal burning will not produce any long-term impacts to the environment if proposed monitoring programs, sale of fly ash, use of compensatory storage during a 100-year flood, and other similar mitigative actions are taken.

The cost of the conversion has been estimated at $35 million. This cost will be offset by reductions in costs of fuel and resultant lower costs to the ratepayer (estimated at $15 million per year). In addition, the conversion will permit a reduction of use of as much as 1.5 million barrels of imported oil per year; or 30 million barrels over the 20-year life of the plant.

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1.0 PURPOSE OF AND NEED FOR ACTION

1.1 BACKGROUND OF ESECA AND FUA

The embargo on petroleum during the winter of 1973-1974 made clear that continued dependence on oil and natural gas was leading the United States (and the world) toward a severe energy crisis. One Congressional response to the embargo was the passage of the Energy Supply and Environmental Coordination Act of 1974 (ESECA), 15 U.S.C. 791 et seq., as amended by the Energy Policy and Conservation Act of 1975 (EPCA), PL 94-163. Under certain circumstances, the Administrator of the Federal Energy Administration (FEA, now a part of the Department of Energy) is authorized by ESECA, as amended by EPCA, to prohibit powerplants and major fuel burning installations (MFBIs) from burning natural gas or petroleum products as their primary energy source and to require that powerplants and MFBIs in the early planning process be designed and constructed to be capable of burning coal as their primary energy source. FEA (DOE) could issue orders implementing this authority through June 30, 1977, when ESECA expired. DOE may, however, amend, repeal, rescind, modify, or enforce such orders through December 31, 1984.

The expiration of ESECA necessitated the introduction of bills into the House and Senate to prohibit the construction of new powerplants without the capability for utilization of coal or alternate fuels. As a result, the Powerplant and Industrial Fuels Use Act (FUA) was passed in 1978 (Public Law 95-620). FUA differs from ESECA and EPCA in several respects:

1) A shift of the burden of proof from the regulatory agency to industry in the case of new facilities;

2) Clarification of authority to prohibit burning of certain fuels and the relation of this authority to all environmental standards including the Clean Air Act and Amendments;

3) Expanded jurisdiction to include existing facilities that do not already have coal burning capability but could burn another fuel or a mixture; and

4) Expansion of authority to include gas turbines and combined cycle facilities (DOE, 1981).

The Omnibus Budget Reconciliation Act of 1981 (OBRA) amended Section 301 of the Fuel Use Act to allow owners 'and operators of electric powerplants to voluntarily certify to the above findings. The amendments also allowed utilities holding valid prohibition orders under FUA or ESECA to elect continued coverage under the applicable sections of those laws, to certify under the new OBRA requirements, or to allow their orders to expire altogether. By letter of December 21, 1981, the utility elected for continued coverage under the provisions of ESECA.

The present action - issuance of a Notice of Effectiveness (NOE) to the Mt. Tom generating station - is being considered under DOE's responsibilities to enforce ESECA prohibition orders through 1984.

1.2 NATURE OF PROHIBITION ORDERS

Prohibition orders issued under ESECA were intended to promote the conversion from natural gas and oil to coal or alternative fuels in existing boilers owned by power companies and industries. An ESECA Prohibition Order was issued on June 30, 1977 (and continued by agreement of December 21, 1981) for Unit 1 of the Holyoke Water Power Company's Mt. Tom generating station in Holyoke, Massachusetts, by the FEA. A Notice of Effectiveness (NOE) to prohibit burning of gas or oil as the primary source of fuel could make effective that Prohibition Order. The issuance of this NOE is the proposed major Federal action which constitutes the subject of this Environmental Impact Statement.

1.3 RATIONALE USED FOR SELECTION OF BOILERS TO RECEIVE PROHIBITION ORDERS

Prior to issuance of the Prohibition Order, the Economic Regulatory Administration (ERA) of DOE determined that the Mt. Tom generating station has, or previously had, the technical capability to use coal as a primary energy source based on the following:

1) The unit had the capability and necessary equipment to burn coal on June 22, 1974, or has acquired it thereafter;

2) The burning of coal is practical and consistent with the purpose of ESECA;

3) Coal and coal transportation facilities will be available during the period the order is in effect; and

4) The prohibition order will not impair the reliability of electricity service.

1.4 RELATIONSHIP OF PRESENT EIS TO PROGRAMMATIC EIS AND OTHER STUDIES

The Department of Energy has determined that issuance of an NOE for the Mt. Tom generating station would be a major Federal action significantly affecting the quality of the human environment. This EIS is being prepared in accordance with the requirements of the National Environmental Policy Act of 1969 (NEPA) (42 USC 4321 et seq.).

This EIS will address the site-specific environmental impact of the action and reasonable alternative actions which could be expected to result from issuance of the NOE. It has been prepared in accordance with the requirements of NEPA and the following additional requirements:

° Regulations promulgated by the Council on Environmental Quality (CEQ) implementing NEPA (40 CFR 1500-1508), and

° DOE NEPA Guidelines (DOE Order 5440.1A and 45 FR 20694-20701).

The major purposes of this statement are to:

° Ensure that appropriate consideration is given to environmental factors at all stages of the agency decision making;

° Provide for and encourage public participation in the decision making process; and

° Identify and assess reasonable alternatives to the proposed action, including the no action alternative, that will avoid or minimize adverse effects upon the human environment.

This site-specific environmental impact statement is the third tier in a three-tiered approach to environmental impact assessment, an approach which conforms to the intent of NEPA in general, and to the CEQ Regulations on implementing NEPA procedures in particular. Section 1508.28 of the CEQ Guidelines defines tiering "as the coverage of general matters in broader environmental impact statements (such as national program or policy statements) with subsequent narrower statements or environmental analyses (such as regional or basinwide program statements or ultimately site-specific statements) incorporating by reference in the general discussion and concentrating solely on the issues specific to the statement subsequently prepared."

The first tier in the impact assessment process associated with fuel conversion is the programmatic analysis. Generic and historic information on the impacts associated with the use of coal and alternate fuels can be found in the Revised Programmatic Environmental Impact Statement for the Energy Supply and Environmental Coordination Act (FEA, 1977). In addition, in April 1979, DOE issued a Final Programmatic Environmental Impact Statement for the Fuel Use Act (DOE, 1979a) assessing the major environmental impacts resulting from the implementation of the Powerplant and Industrial Fuel Use Act. That impact statement addresses overall program impacts rather than site-specific impacts, and is predicated on the assumption that coal will be the primary fuel substituted for oil and natural gas in the short term (1990).

The second tier of the impact analysis is the Northeast Regional Environmental Impact Statement (NEREIS) which has been issued in draft (DOE, 1981). This document responds to the need to assess the potential for cumulative and interactive impacts among powerplants located in proximity to each other. This type of analysis is considered appropriate since more than half (42) of the powerplants currently subject to, or under consideration for, prohibition orders are located in ten states in the northeastern United States. The NEREIS and four technical documents which provide the data base for the regional analysis emphasize four major interrelated issues: (1) air quality, (2) solid waste disposal, (3) fuel supply and the transportation of fuel and solid waste, and (4) health effects. The technical documents are designed to provide a portion of the data base for the site-specific environmental anlaysis as well as a broader perspective for assessing the potential impacts of proposed conversion actions. Detailed site-specific issues are not treated in the NEREIS; rather, generic issues that are cumulative or interactive on a regional basis are emphasized. When addressing issues in the site-specific documents where the use of generic information is most appropriate, the information is incorporated directly from the NEREIS.

The analysis in the Northeast Regional Environmental Impact Statement is based on an assessment of the impacts associated with four air pollution emission scenarios (Table 1-1). This component of the analysis was conducted at the subregional level. The four subregions center around Boston, New York, Philadelphia, and Baltimore. In the Boston subregion the analysis is based on the interaction of 12 potential conversion candidates, including the plant that is the subject of this site-specific EIS. This approach to air quality analysis assumes that all the conversion candidates will in fact convert. It is a conservative approach and produces worst-case results since it is highly unlikely that all coal-capable plants in the subregion will actually choose to convert. The findings of the Northeast Regional Environmental Impact Statement are presented in summary form in Section 2.7 of this document.

Facilities in Massachusetts in addition to the Mt. Tom generating station which are included in the third tier are Brayton Point and Salem Harbor (see Figure 2-1). The final EIS for Brayton Point was issued in September 1979 (DOE, 1979b). The draft EIS for Salem Harbor was issued in February 1982 (DOE, 1982), and the final EIS will be issued shortly.

Under the Massachusetts Environmental Policy Act (MEPA), the Massachusetts Executive Office of Environmental Affairs must conduct an environmental review of these conversions. The MEPA process includes many of the issues of concern included in the National Environmental Policy Act of 1969. To satisfy requirements of MEPA, the utility submitted an environmental impact report to the state in September 1981 (NUSCO, 1981d).

1.5 DESCRIPTION OF EXISTING FACILITY

The Mt. Tom generating station of Holyoke Water Power Company (HWP), occupies an 89-acre site on the west bank of the Connecticut River near the northern city limits of Holyoke, Hampden County, Massachusetts (Figure 1-1). The plant is an existing facility which went on line in 1960 burning coal. In 1970 the unit switched to oil, which it continued to use as its major energy source until December 1981, except for a short period in 1973-1974 when the unit was returned to coal burning during the oil embargo. The unit transferred back to coal burning in December 1981 under terms of a Memorandum of Understanding (MOU) with the state and a Delayed Compliance Order (DCO) issued by EPA Region I.

Under the low-sulfur coal conversion the Mt. Tom generating station has reconverted to burning coal as its major energy source. Since the plant was originally designed to burn coal, most of the equipment and the space needed to handle, store, and burn coal and dispose of waste is in place or available onsite (Figure 1-2). The conversion has required upgrading and replacing equipment which is in disrepair or which does not meet present regulatory standards. Because the plant is an operating facility, the impacts which will be produced are incremental; that is, they reflect only those changes produced by the change in fuel from oil back to coal.

An overview of plant systems necessary to the burning of low-sulfur coal follows. Modifications to the plant required to burn coal and to meet environmental and other regulatory requirements are discussed under the low-sulfur coal alternative in Section 2.3.1. New and reactivated facilities are shown on Figure 1-2. Environmental consequences of this alternative are summarized in Section 2.3.2 and are described in detail in Chapter 4.0. Regulations governing the proposed action, including the MOU, the DCO, and the National Pollutant Discharge Elimination System (NPDES) permit are discussed in Section 1.6.

TABLE 1-1

DESCRIPTION OF AIR QUALITY SCENARIOS[a]

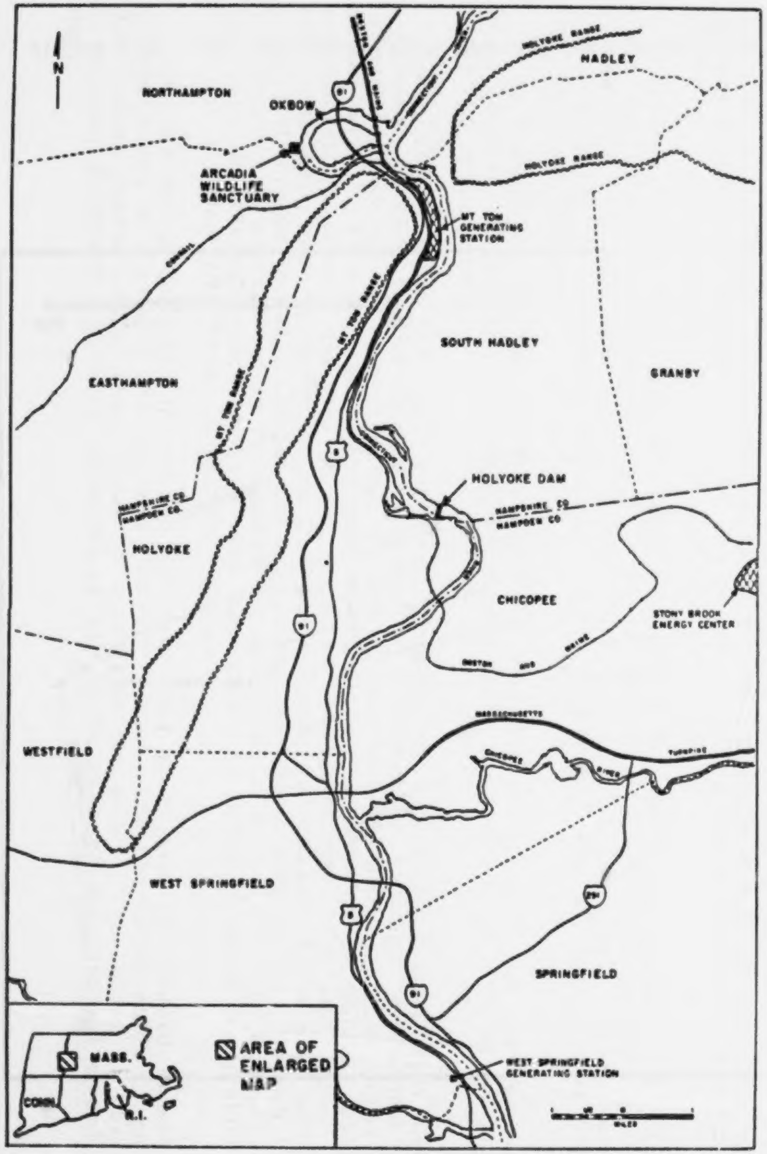
Base Case	The emissions from burning oil with the limitations on SO_2 as specified in the current State Implementation Plan (SIP). No conversion to coal.
Scenarios	
Oil SIP	The emissions from burning coal with the limitations on SO_2 as specified for oil in the current SIP (see Table F.2). Although the emissions limitation does not increase, SO_2 emissions actually would increase under this scenario due to changes in plant capacity factor resulting from conversion from oil to coal. The oil SIP limitation data used in this scenario are listed in Table F.3.
Coal SIP	The emissions from burning coal with limitations on SO_2, as specified in the current coal SIP[b] (see Table F.2). The coal SIPs vary widely and in many states requests for revision have been made. Emission limitations for the coal SIP are listed in Table F.4.
1971 NSPS	The emissions from burning coal with limitations on SO_2 as specified by the 1971 New Source Performance Standards. It is assumed that under this scenario all facilities would convert at a set emission rate (1.2 lb $SO_2/10^6$ Btu), the emission level associated with the 1971 New Source Performance Standards. This emission rate is based on the use of the lowest sulfur content coal generally available at a reasonable price on the east coast, and is identical to the emission limitations for new utilities set by USEPA from 1971 to 1977.[c] This emission level was selected on the assumption that compliance coal (coal sufficiently low in sulfur content that flue-gas desulfurization would not be required) would be available.
Modified Coal SIP	The emission limitation proposed by certain utilities and state agencies for specific powerplants, with all other powerplants modeled at the coal SIP. This scenario includes SIP changes as well as the taller stack heights proposed by the utilities. It is designed to address the numerous comments received from utilities and state agencies during the regional scoping meetings held the week of July 14, 1980, as well as those received from meetings with the individual utilities. The Modified Coal SIP scenario is designed to bracket a reasonable high-emission scenario. The proposals are either at or above present coal SIP emission limitations. Those stations where an increase in the SIP is being proposed are listed in Table 3.7, which also includes present emission limitations for those stations.
Mitigative Analysis	In those areas where more than half of the PSD increment is predicted to be consumed by the proposed conversions, strategies to reduce the degradation were developed. Variations in individual plant emission limitations were developed to minimize air quality impacts while optimizing conversion for those areas where emissions resulting from the conversions are predicted to approach or violate air quality standards. All other stations were assumed to be under the coal SIPs. These scenarios are listed in Table 3.8 and are discussed in greater detail in Section 5.1.3.2. Although such conversions are exempt from new source review under the Clean Air Act Prevention of Significant Deterioration (PSD) regulations, the scenarios listed in Table 3.8 were analyzed to determine the conversions. The mitigating scenario was developed following an analysis of the results of the other scenarios. Those facilities which would generate the greatest impacts on air quality were determined, and emission reductions likely to reduce the impacts were developed.

[a] To assess the incremental impact related to the proposed action for the four scenarious plus the mitigative analysis, existing emissions (i.e., the emissions from burning oil at the current oil SIP) were subtracted from each of the scenario emissions.

[b] The coal SIP emission estimates are from data developed jointly by USEPA and USDOE in support of the Utility Oil Backout bill (S 2470). These data represent the best available estimates of currently required emission levels following conversions. Although in some cases there is disagreement as to the actual SIP levels in force, the other levels claimed are in nearly every case lower, and thus the estimates shown here represent realistic upper bounds on SO_2 emissions following conversion. The actual numerical values of the SIP limitations are relatively unimportant in any case. The analyses in this document deal with trends in SO_2 concentrations, and are designed to locate those areas within the Region that are potentially most affected by cumulative conversions. The conversion scenarios are designed to examine the effects of minimal increases in SO_2 emissions, an achievable middle level of emissions, and a realistic maximum emission rate. Thus, the assumed scenarios, even if not in absolute numerical agreement with every listed or proposed SIP emission rate for every facility under investigation, do adequately bracket the likely air quality effects of the proposed conversions.

[c] USEPA (1971).

NOTE: All tables and sections referred to herein are from the Northeast Regional EIS.



N
NORTHAMPTON
OXBOW
ARCADIA WILDLIFE SANCTUARY
HOLYOKE RANGE
HADLEY
HOLYOKE RANGE
MT TOM GENERATING STATION
91
EASTHAMPTON
MT TOM RANGE
SOUTH HADLEY
GRANBY
5
HOLYOKE DAM
HAMPSHIRE CO
HAMPDEN CO
HOLYOKE
CHICOPEE
STONY BROOK ENERGY CENTER
BOSTON AND MAINE
MASSACHUSETTS TURNPIKE
CHICOPEE RIVER
WESTFIELD
WEST SPRINGFIELD
291
SPRINGFIELD
MASS.
CONN.
R.I.
AREA OF ENLARGED MAP
WEST SPRINGFIELD GENERATING STATION
MILES

Figure 1-1. Mt. Tom Generation Station and Vicinity.

TABLE 1-2

MT. TOM GENERATING STATION
DESIGN AND OPERATING DATA AT FULL LOAD

	Unit 1
Year Completed	1960
Revised Boiler Rating	136[a]
Maximum Steam Capacity (lbs/hr)	1,000,000
Air Flow @ 100% Load (CFM)	246,510
Principal 1980 Fuel	oil
Heat Rate (million Btu/MW)	9.912
Wet or Dry Bottom	Dry
Stack Height (feet)	370
Stack Diameter (feet)	10
Exit Velocity (ft/sec)	76.7
Exit Temperature (°F)	278
Flue Gas Rate (million lbs/hr)	1,165
Tested Particulate Control Efficiency (%)	92.9
Source: FPC Form 67, 1979.[a]	

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[a] Note that although this rating is used in FPC Form 67, 1979, the net generating capacity is considered 145 MW.

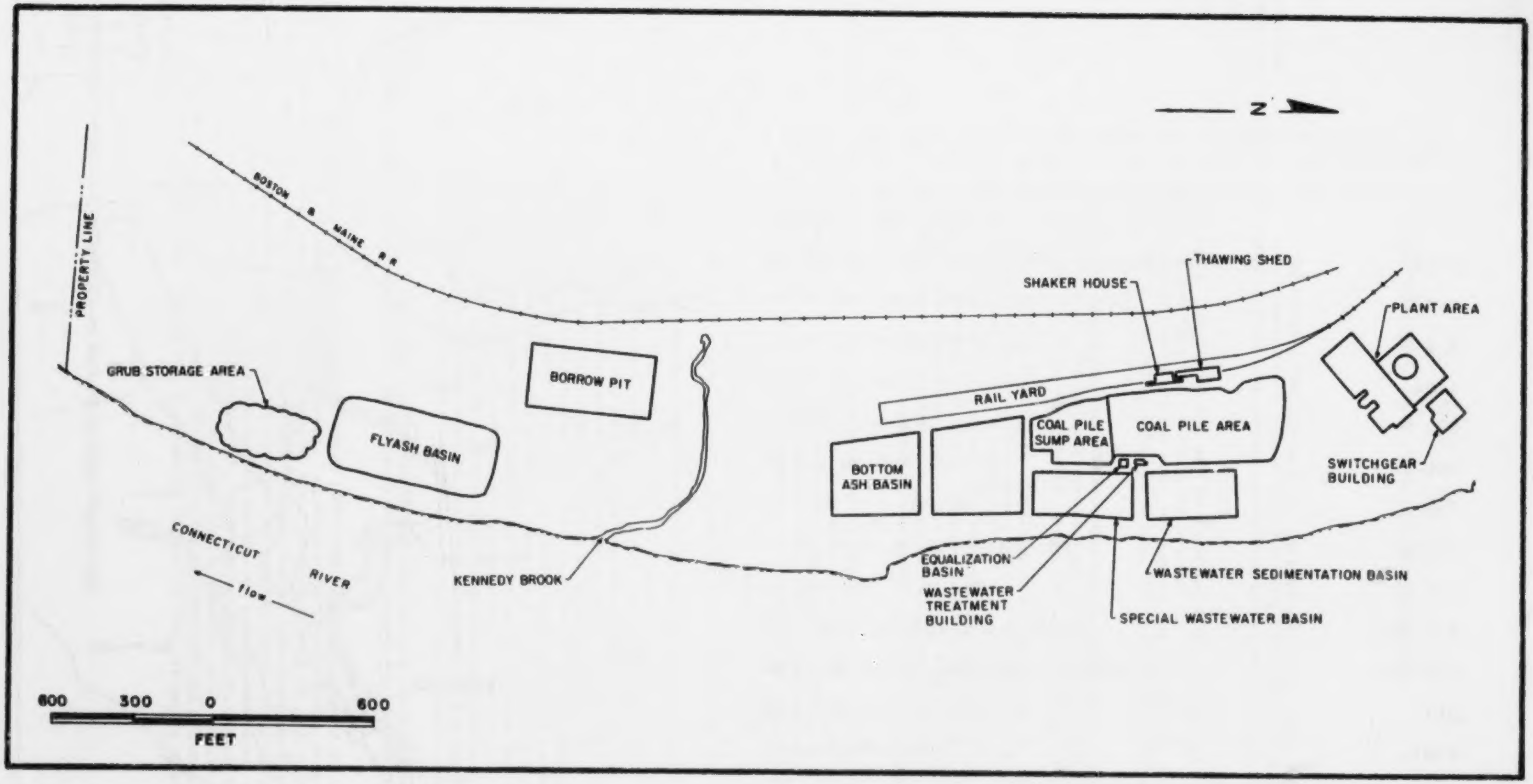
N
PROPERTY LINE
BOSTON & MAINE R.R.
GRUB STORAGE AREA
FLYASH BASIN
BORROW PIT
CONNECTICUT RIVER
flow
KENNEDY BROOK
BOTTOM ASH BASIN
RAIL YARD
COAL PILE SUMP AREA
COAL PILE AREA
SHAKER HOUSE
THAWING SHED
PLANT AREA
SWITCHGEAR BUILDING
EQUALIZATION BASIN
WASTEWATER TREATMENT BUILDING
SPECIAL WASTEWATER BASIN
WASTEWATER SEDIMENTATION BASIN
600
300
0
600
FEET

Figure 1-2. Mt. Tom Generation Station Coal Conversion Modifications - Present Configuration

Coal is brought to the plant by train and delivered to the HPC-owned sidings at the plant. Meeting plant needs requires a 70-car train (7,000 tons of coal) about every 5 days. From 63,000 to 125,000 tons, or 60 to 90 days supply is stockpiled in a lined area. The coal pile occupies approximately 54,000 square feet at an average height of 50 feet. Coal pile runoff is directed to a lined collection area near the coal pile, allowing any coal carried in the runoff to be reclaimed.

The rail unloading facility consists of an existing thawing shed and a shaker house. The thawing shed is used to unfreeze coal from the cars. The shaker house contains an electric motor connected to an eccentric cam which in turn is mounted within a steel framework. The framework is lowered onto the top of the railcar and vibrates the car, shaking the car so that the coal falls into the hoppers. The existing unloading equipment requires 14 to 16 hours to unload a unit train (7,000 tons).

Coal is transferred from the hoppers in the shaker house by underground conveyors and is moved to the transfer house. Coal can either be conveyed to the crusher house or sent directly to the coal pile for storage. Coal is crushed into 3/4-inch pieces in the crusher house. It then moves in a covered conveyor to the plant where it is stored in four bins. Under the bins, the coal feed system weighs the coal and distributes it to the four pulverizers. The pulverizers then crush the coal into dust-sized particles and the coal dust is fed pneumatically into the boilers.

The existing boiler is a front-firing, dry bottom unit. The plant has a net generating capacity of 145 MW (Northeast Utilities Service Company [NUSCO], 1981b).

Cooling of the condenser is accomplished by a once-through system that withdraws about 133 million gallons of water per day (MGD) from the Connecticut River and returns it to the river with a maximum temperature increase of 32°F. Boiler makeup water, which replaces water lost through blowdown, is about 43,000 gallons per day (gpd). This water is treated chemically to prevent corrosion within the boiler system. Boiler blowdown is directed to the wastewater ponds (Figure 1-2). An additional 375,000 gpd is required for bottom ash sluice waters, and 875,000 gpd for fly ash sluicing.

Normal plant wastewaters include sand filter backwash, demineralizer regeneration, boiler blowdown, boiler seal water, floor drains, pump base drains, and other miscellaneous wastes. These wastewaters are collected at a rate of about 110,000 gallons per day. The normal plant wastewater stream is not dependent on fuel type and therefore has not changed in quality or quantity upon conversion to coal. Treatment must maintain the sedimentation basin at a pH of about 8.5, which is within the discharge limit. The retention time in this basin (more than 35 days) allows the small amount of dissolved metals in the waste stream to become insoluble and settle, bringing any discharge within the NPDES limits.

Maintenance washes include furnace fireside wash, air heater, precipitator, fan, and stack washes and chemical cleanings. These wastewaters are high volume concentrated wastewaters but only occur about once a year during plant outages. These wastes are directed to the lined special wastewater basin where they may be held for as long as a year before treatment.

Wastewater discharges from the yard and roof drains, oil trap and furnace seal outflows, highway runoff and the traveling screen wash are treated and discharged according to NPDES requirements.

Fly ash is collected by electrostatic precipitators and mechanical dust collectors (cyclones). This station system consists of a multiclone (multiple mechanical cyclone collection) followed by approximately 31,000 square feet of electrostaic precipitator collecting area. This original equipment was designed to achieve 95 percent particulate removal efficiency at a gas flow of 401,000 ACFM (based on the ASTM test method). However, the unit was tested at a gas flow in the order of 550,000 ACFM and achieved 93 percent efficiency in 1963. Under the low-sulfur coal conversion the dry fly ash is mixed with water and wet sluiced to an unlined fly ash pond at a rate of approximately 875,000 gpd (NUSCO, 1981c), where the silt- and clay-size ash particles settle by gravity. The pond has a capacity of about 23 million gallons.

Bottom ash is collected in the ash pit below the boiler and wet sluiced to one of two unlined ponds at a rate of 375,000 gpd (NUSCO, 1981c). The particles which range in size from coarse gravel to fine sand settle by gravity in the pond. The bottom ash basins are to be used alternately to allow accumulated ash to be removed for disposal elsewhere onsite.

The bottom ash and fly ash sluice system placed in service at this time are to be part of the permanent wastewater system as described in Section 2.3.1.4. The temporary treatment system has been installed for the normal plant wastewater stream and used until the final treatment system is complete in late 1982.

Coal pile runoff is collected in a lined impoundment area adjacent to the coal pile. This area is of sufficient size to contain the normal rainfall amounts over a 6-month period, and no runoff is expeced from this impoundment. Should it become necessary to remove water from this impoundment, it must be pretreated with caustic soda to adjust the pH and pumped to the special wastewater basin for further treatment.

1.6 REVIEWS AND APPROVALS

Permits required for present operation of the Mt. Tom generating station are summarized on Table 1-3 at the end of this section. The NPDES permit and the DCO are the most significant of these with regard to environmental considerations. These together with the MOU are summarized in the following sections. The NPDES permit, the DCO, and the SIP revision are presented in Appendix C.

1.6.1 National Pollutant Discharge Elimination System (NPDES)

A renewal of the existing NPDES permit was granted on November 30, 1981 to become effective December 1, 1981. Under that permit, the station has the folloiwng discharges:

Outfall		Average Per Month
001	Condenser cooling water	133.2 MGD
002	Wastewater treatment system	0.11 MGD
004	Yard drains	0.029 MGD
005	Traveling screen wash	0.374 MGD
006	Reflecting pond overflow	---
007	Oil trap overflow/highway runoff	0.01 MGD
008 and 009	Bottom ash settling basin	0.25 MGD
010 and 011	Fly ash settling basin	0.11 MGD

1.6.2 Delayed Compliance Order (DCO)

Section 113(d)(5) of the Clean Air Act allows EPA to issue a Delayed Compliance Order (DCO) to the recipient of a Federal prohibition order. A DCO was issued by EPA Region I to the Mt. Tom generating station to be effective November 24, 1981. This order is in effect until February 15, 1984, at which time the HWP must have completed installation of the new electrostatic precipitators. The order permits initial particulate emissions of 0.48 pound particulate matter (PM) per million Btu for the first 240 days of coal burning. For the remainder of the DCO period the particulate emissions must not exceed 0.35 per million Btu gross heat input. Upon expiration of the DCO, the utility will be required to meet a new standard of 0.08 lb PM/million Btu.

In order to obtain the DCO, the utility was required to demonstrate that the proposed fuel conversion during the DCO period:

1. Would not cause or contribute to any violation of the primary national ambient air quality standards (NAAQS); and

2. Would have only an infrequent and insignificant effect on particulate matter (PM) concentrations in PM nonattainment areas in the air quality control region ("refutation of regional limitation").

Additional requirements of the DCO are:

- The ash content of the coal to be burned shall not exceed 9 percent by weight (dry basis after the first 240 days of coal burning).

- A new DCO opacity limit is to be developed.

° A detailed plan for control of fugitive dust emissions must be developed by HWP.

° Extensive testing and monitoring programs are to be established to monitor stack emissions and opacity, fuel characteristics, control systems performance, ambient air quality, and meteorological characteristics in the neighborhood of the station.

° The best practical system for emission reduction (BPSER) was determined to consist of a major upgrading of the existing electrostatic precipitator plus the installation of a flue gas conditioning system.

° Seven monitoring stations must be maintained by HWP as follows:

  - Northampton area, Northampton; TSP, SO_2 will be required only if the TSP levels exceed the secondary NAAQS.
  - Pine Street, South Hadley; TSP and SO_2.
  - Mt. Tom ski area, Holyoke; SO_2.
  - Mt. Tom Range, Holyoke; SO_2, TSP will be required only if SO_2 levels exceed the current NAAQS.
  - Mt. Tom coal pile (to measure fugitive impacts), Holyoke; TSP.
  - Mt. Tom stackbase, Holyoke; SO_2.
  - Summit House, Skinner State Park, bordering Hadley and South Hadley; TSP and SO_2.

1.6.3 Memorandum of Understanding

On March 6, 1980, the Governor of the Commonwealth of Massachusetts and representatives of the DEQE and the Holyoke Water Power Company (HWP) signed a memorandum of understanding (MOU) concerning a specific process by which the Mt. Tom generating station could be converted to coal burning. The MOU pledged the signatories to work together to realize the MOU coal conversion scenario. The MOU did not in itself constitute a prescribed manner in which the coal conversion must take place, nor did it provide for any variance of laws or regulations, either Federal, state, or local, with which a coal conversion at the Mt. Tom station must comply.

In the MOU, the parties agreed that a coal conversion is desirable, and further that the HWP does not have the financial capability to immediately convert the station to coal while meeting all of the pertinent environmental regulations. The MOU posed a resolution to this difficulty through the use of the DCO, which has been issued by EPA, under which certain emission standards applicable to the station are to be temporarily relaxed for a certain period of time following the initiation of coal burning. While the DCO is in effect, two-thirds of the savings realized by the use of coal rather than oil as the generating station fuel are to be retained by HWP and accumulated for the purchase and installation of improved emission control equipment. The remaining one-third such savings is to be passed on to the ratepayers. This financing method, called an Oil Conservation Adjustment, has been adopted by the Commonwealth of Massachusetts to assist utilities in converting to coal. The MOU specifies environmental standards for the period that the DCO is in effect and for the period following the expiration of the DCO. These standards apply to air and water quality, solid waste generation and disposal, and ambient noise levels.

The MOU doe not pre-empt DCO conditions stipulated by EPA or limitations that appear in the revised SIP proposed by DEQE and approved by EPA.

TABLE 1-3

PERMITS/APPROVALS OBTAINED

Page 1 of 3

PERMIT/APPROVAL/ACTION	DATE OF ISSUANCE OR ACTION	ISSUING AGENCY	PURPOSE	AUTHORITY
Federal				
1. NPDES Permit (National Pollutant Discharge Elimination Sytem)	November 30, 1981	United States Environmental Protection Agency and Massachusetts Department of of Environmental Quality Engineering	To permit point discharges of pollutants to waters of United States. Includes Water Quality Certification from DEQE pursuant to G.L. c. 21, Sections 26A, 27 (12) and 43	33 USC Section 1342, and G.L. c. 21, Sections 26A 27 (12) and 43.
2. Delayed Compliance Order	November 24, 1981	United States Environmental Protection Agency	To permit operation of plant before new precipitator is installed	42 USC Sections 7413(d)(3) and 7414
State				
1. Clarification (not approval) of authority to burn high-sulfur content fuel	July 22, 1981 (letter from A. Iontosca); November 18, 1981 (letter from A. Cortese)	Massachusetts Department of Environmental Quality Engineering	To clarify that State Implementation Plan permits burning of all fossil fuel (not just fuel oil) with a sulfur content of 1.21 pounds per million Btu heat release potential	310 CMR Section 7.05(1)(c)
2. Plan Approval for Solid Waste Disposal	November 27, 1981 (including site inspection Certificate of Compliance)	Massachusetts Department of Environmental Quality Engineering	To permit use of solid waste disposal facilities	G.L. c. 111, Section 105A
3. Discharge to Ground Water and Wastewater Treatment Facilities Permit	November 27, 1981	Massachusetts Department of Environmental Quality Engineering	To allow discharges to ground water from solid waste disposal facilities and temporary wastewtaer treatment facilities and to allow construction and operation of temporary wastewater treatment facilities	G.L. c. 21 Sections 27 and 43
4. Boiler Inspection	November 25, 1981	(Kemper Insurance)	To permit operation of modified boiler	G.L. c. 146, Sections 8 and 23; 522 CMR Section 15.00 *et seq.*
5. Approval of Plans for Temporary Wastewater Treatment Facility	November 25, 1981	Massachusetts Department of Environmental Quality Engineering	Approval of plans for temporary wastewater treatment facilities until permanent facilities constructed	G.L. c. 21, Sections 26A, 27(9) and (13) and 43(2) and (5)

TABLE 1-3 (Continued)

PERMIT/APPROVAL/ACTION	DATE OF ISSUANCE OR ACTION	ISSUING AGENCY	PURPOSE	AUTHORITY
Local				
1. Special Permit for structures in floodplain	June 29, 1981 (letter)	Holyoke Board of Aldermen	Construction of new 4160 volt switchgear building, new wastewater treatment building, new load center building	Section 4-3.d. of City of Holyoke Ordinances
2. Building Permit	July 1, 1981 (Certificate No. 215)	Holyoke Department of Codes and Inspections	Construction of new structures described above and upgrading of railroad car thaw shed and car shaker building	Massachusetts Building Code and City of Holyoke Code of Ordinances
3. Order of Conditions for certain construction activities in wetlands	June 15, 1981 (DEQE File No. 186-28)	Holyoke Conservation Commission	Construction in wetlands of three new structures described above	C.L. c. 131, Section 40; 310 CMR 10.00
4. Determination of Non-applicability of Wetlands Act	June 16, 1981 (DEQE (File No. 186-28)	Holyoke Conservation Commission	To establish no jurisdiction of HCC over any activities in wetlands except those for which order of conditions granted in item 3 above	G.L. c. 131, Section 40
5. Site Assignments for Solid Waste Disposal	October 13, 1981	Holyoke Board of Health	To permit siting of solid waste disposal facilities	G.L. c. 111, Section 150A
6. Special Permit for Extended Hours of Construction (through November 30, 1981)	October 21, 1981 (Certificate No. 2282)	Holyoke Board of Public Works	To permit construction activities after 6:00 pm and before 7:00 am on weekdays	Section 12-21(d) of the City of Holyoke Ordinances
7. Temporary Emergency Certification to Operate Wastewater Treatment Facilities	November 30, 1981	Board of Certification of Operators of Wastewater Treatment	To permit operation of waste facilities until permanent certification obtained	G.L. c. 112, 87AAAA and 87BBBB
8. Occupancy Certificates	November 30, 1981	Holyoke Department of Codes and Inspections	Occupancy of new 4160 volt switchgear building, railroad car thaw shed and railroad car shaker building	Massachusetts Building Code and City of Holyoke Code or Ordinances

PERMIT/APPROVAL/ACTION	DATE OF ISSUANCE OR ACTION	ISSUING AGENCY	PURPOSE	AUTHORITY
Local (Cont'd)				
9. License to Store fuel Oil in Tanks and Annual Registrations	April 1, 1960 License (for a 1,200 gallon above-ground tank and also for a 16,000 gallon underground tank)	Department of Public Safety, Division of Fire Prevention, issued by Clerk, Board of Public Safety for the City of Holyoke	Authorizes the storage of fuel oil	G.L. c. 148, Sections 9 and 13; Code of Ordinances of the City of Holyoke, Sections 71-5 and 11.1
	November 18, 1969 License (for a 2,819,880 gallon above-ground tank)			
	August 6, 1970 License (for a 9,900 gallon underground tank)			
	June 15, 1972 License (for a 3,612,000 gallon above-ground tank)			
	April 1981 (Annual Registrations for the above Licenses except for the 9,900 gallon tank)			
10. Permit to Construct, maintain, or use a tank located above-ground containing 100,000 gallons or more of fluid other than water	December 3, 1969 Permit (for the 2,819 gallon above-ground tank)	Commissioner, Department of Public Safety	Authorizes the construction, maintenance, and use of the tank	G.L. c. 148, Section 37
11. Order of Conditions for Phase II Construction Activities	March 18, 1982 (DEQE File No. 186-30)	Holyoke Conservation Commission	Construction in wetlands of: electrostatic precipitator, new silo complex and employee facility	G.L. c. 131, Section 40; 310 CMR 10.00

Source: Tabulation prepared by NUSCO, 1982.

2.0 ALTERNATIVES

2.1 NEED FOR ALTERNATIVE CONSIDERATIONS

The final regulations implementing the procedural provisions of the National Environmental Policy Act (NEPA) state that consideration of alternatives, including the proposed action, "is the heart of the environmental impact statement." This section of the document is intended to:

- ° Review and evaluate all reasonable alternatives;
  - include reasonable alternatives not within the jurisdiction of the lead agency;
  - include the "no action" alternative;
- ° Discuss reasons why certain of the reasonable alternatives were eliminated from detailed study;
- ° Devote substantial treatment to all other reasonable alternatives, including the proposed action;
- ° Identify the agency's perferred action;
- ° Include appropriate mitigative measures.

The environmental impacts are presented in a comparative form which defines the issues and provides a basis for choice by the decision maker and the public (see Section 2.6, Table 2-2).

2.2 NO ACTION ALTERNATIVE

If a Notice of Effectiveness is not issued by DOE, several options are open to the utility. Among the most viable of these are to:

1) Continue with the present conversion, to the extent possible under present law (MOU/DCO);
2) Return to operation with oil; or
3) Early retirement of the unit.

The first of these options is discussed in Sections 1.5 and 2.3. It should be noted, however, that current law only allows issuance of a DCO to recipients of Federal prohibition orders. The early retirement option may be considered by the utility whether or not an NOE is issued; this alternative, and its efects on system reliability are discussed in Section 2.5.4.

Should HWP select the second option, return to oil burning, the long-term environmental effects would be the same as those which would have continued had the utility not converted to coal. This would require the importation of from 10 to 16 MMB of oil over the next 10 years, depending on the percentage of time the plant is operating. At the rate of $34.75 per barrel expected at the time of conversion (late 1981), this is from $348 to more than $417 million (in 1981 dollars) in national balance of payment losses. Coal of the type being burned is estimated to cost $61 per ton (Ellis, 1980) or about $187 million for the period; assuming the plant is on line 80 percent of the time, a net savings of as much as $230 million compared to oil would be accrued for the period 1982-1990. Impacts for mining this quantity of coal are reviewed in the programmatic EIS (DOE, 1979a; see also Section 5.2.2).

2.3 LOW-SULFUR COAL CONVERSION

Under the conversion as undertaken by the utility, the Mt. Tom generating station has reconverted to burning low-sulfur coal as its major energy source. Since the plant was originally designed to burn coal, most of the equipment and the space needed to handle, store, and burn coal and dispose of waste was in place or was available onsite (see Figure 1-2). The conversion has required upgrading and replacing equipment which was in disrepair or which did not meet present regulatory standards. Because the plant is an operating facility, the impacts which may occur are incremental; that is, they reflect only those changes produced by the change in fuel from oil back to coal.

An overview of plant systems necessary to the burning of low-sulfur coal was presented in Section 1.5. Modifications to the plant required to burn coal and to meet environmental and other regulatory requirements are discussed in Section 2.3.1. New and reactivated facilities are shown on Figure 1-2. Environmental consequences of this alternative are summarized in Section 2.3.2 and are described in detail in Chapter 4.0. Regulations governing the conversion were discussed in Section 1.6.

2.3.1 Plant System Modifications

While most of the equipment necessary to reconvert to burning coal was in place, this equipment had not been used for several years and much of it required upgrading and/or repairs either to make it coal capable or to meet environmental or other regulatory standards. These modifications are discussed in the following paragraphs to provide a basis for evaluating the expected impacts of the fuel conversion.

2.3.1.1 Coal Selection

Characteristics of a coal typical of that being burned at the Mt. Tom generating station are given in Table 2-1. This coal differs slightly from the boiler performance "design coal" which is also given in the table. The fuel is a washed coal with a sulfur content of 1.21 lbs/10^6 Btu heat input. This sulfur-in-fuel standard corresponds to fuel oil containing 2.2 percent sulfur (the fuel burned under the recent oil burning Mt. Tom operation), or to project coal with an average sulfur content of 1.5 percent by weight. The coal will come from eastern bituminous fields, from sources which meet the required specifications.

TABLE 2-1

FUEL CHARACTERISTICS

	Project Coal	Design Coal	No. 6 Fuel Oil
Heat Content[a]	12,500 minimum	12,400	138,700
Sulfur Content (%)	1.2-1.5	1.22	2.2
Ash Content (%)	9.0 maximum	12.2	
Moisture Content (%)	3.0-6.0	6.1	
Volatile Content (%)	25-35	30.4	
Grindability, Hardgrove	60+ minimum	60	

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[a] Heat contents for coal given in Btu/lb, and for oil in Btu/gal.

2.3.1.2 Coal Handling and Burning

Repairs have been required to the rail yards and the yard engine. In the thawing shed, a new, quiet radiant electric heater system is to be installed by the winter of 1982-1983 to replace the oil burner which was a source of considerable noise during earlier coal burning. The shaker house will be lined with sound absorbing material and the building will also be further enclosed. Operator enclosures will be provided for personnel working within the shaker house (NUSCO, 1981d). A wall 130 feet long and 40 feet high has been erected parallel to the shaker house and 25 feet from the center line of the building to reduce noise impacts across the river.

The coal handling and transfer equipment and pulverizer capacity were upgraded and major repairs to the boilers were required before coal could be burned.

The electrostatic precipitators have been operated in excess of design capacity. As a result, the multiclone has experienced severe deterioration. Without repair, the particulate control system could achieve a maximum efficiency of 87.5 percent when the station is burning coal (estimated 12,500 Btu/lb, 10 percent ash, 1.5 percent sulfur).

The first step of upgrading the existing particulate matter control system resulted in an emission rate of 0.48 lb/10^6 Btu using the proposed project coal. The existing mechanical collector and the electrostatic systems are being upgraded to meet DCO requirements.

The second step of upgrading, consists of installing new efficient, electrostatic precipitators that will allow compliance with the Massachusetts SIP to support long-term burning of coal.

Three new buildings are required as part of the conversion plan: a switchgear building is in service; a load center building adjacent to the thawing shed to distribute 480 volts to the infrared heaters in the adjacent coal car thawing shed will be completed before the winter season 1982-1983; and a wastewater treatment building is under construction.

2.3.1.3 Ash Disposal

Ash produced from the burning of coal will be equivalent to about 9 percent of the weight of the coal. The Mt. Tom generating station is expected to burn about 384,000 tons/year of coal. This will result in more than 29,000 tons of fly ash and 8,000 tons of bottom ash.

To provide for storage of ash as well as wastewater, the area occupied by the wastewater and botom ash ponds and a previously used fly ash pond south of Kennedy Brook, have been reactivated (Figure 1-2). Diking materials were excavated from the site. The facility commenced coal firing using one fly ash pond with a capacity of approximately 23 million gallons (sufficient for 1 1/2 to 2 years of service) and two unlined bottom ash ponds of 8 million gallon capacity each (NUSCO, 1981d). Additional acreage onsite presently unused or used for farming or for oil storage could be developed for additional storage if permission were granted to construct the waste storage ponds on the floodplain. The utility plans to use the existing ponds initially, but their preferred alternative is to sell the fly ash for reuse, depending on the characteristics of the ash and the potential market (see Section 2.5.3).

2.3.1.4 Water Use/Treatment

By far the greatest volume of water required by the plant - 133 MGD - is for the once-through cooling process. This need will not be affected by the change in fuel. Needs for sluicing water will be about one million gallons per day higher than present sluicing requirements. Plans for water use and treatment can be divided into three phases: Phase I corresponds to the construction phase, prior to initial coal burning; Phase II began with the conversion to coal and will continue until the redesigned waste treatment system is in operation; Phase III would be in effect for the remainder of the life of the plant which is expected to be about 20 years. These phases are discussed in the following sections using information from the updated NPDES permit application submitted to the state (NUSCO, 1981c), the final Environmental Impact Report submitted to DEQE by the utility (NUSCO, 1981d), the new NPDES permit; and the interim treatment facilities permit.

Construction Period

During the construction period, a water management policy was in effect to allow continued plant operation, minimize interference with construction, and continue the "zero discharge operation" which was in effect during oil burning.

Interim Treatment System

An interim treatment system was required to meet permit requirements for the period between the conversion to coal and the completion of the permanent facilities. Since this system is in operation, it is discussed in Section 1.5

Permanent Wastewater Treatment System

Construction of the permanent wastewater treatment system was scheduled to begin in late May 1982, and the facility is scheduled to be in operation during 1982. The system to be constructed consists of wastewater collection, equalization, pH adjustment, polymer addition, sedimentation, final pH adjustment, effluent polishing, environmental monitoring, and sludge handling (NUSCO, 1981c). Fly ash sluice water, bottom ash sluice water, normal plant wastewater, coal pile runoff, and maintenance cleaning wastewater are to be treated separately, and any discharges must be through NPDES approved discharges. Direct discharges of once-through cooling water, rainwater runoff, traveling screen wash water, and reflecting pond overflow will be continued. The modified streams and their treatment are discussed in the following paragraphs.

Bottom Ash Transport Water

Bottom ash is collected in the ash pit below the boiler and wet sluiced to one of two unlined bottom ash ponds at a rate of about 375,000 gallons per day. Use of the bottom ash ponds will be alternated annually. Initially more than 30-days retention time was provided; however, available data indicate that only one day's retention is required to reduce suspended solids levels to the NPDES discharge limits prescribed. Since only one ash pond is to be in use at any time, there will not be simultaneous discharge from these outfalls.

Fly Ash Transport Water

Until March 1983, fly ash may be collected and wet sluiced using a slip stream from the condensor cooling water discharge at a maximum rate of 875,000 GPD to the fly ash pond for retention and settling. Any overflow from this pond will be discharged to the river under the NPDES permit. This pond has a capacity of 23 million gallons which should provide 1-1/2 to 2 years ash storage capacity based on the quantities expected to be generated. The utility is continuing to pursue the sale of fly ash, and expects to have a market for all fly ash produced depending upon mineral content.

2.3.2 Impacts of the Low-sulfur Coal Conversion

Impacts to the natural and manmade environment can be identified as those incremental changes due to conversion from burning oil to burning low-sulfur coal. Air quality and water quality changes and increases in noise levels are established by the MOU and the DCO, and by modifications to the NPDES permit and by other permits required (see Section 1.6). The existing environmental conditions in the site vicinity are discussed in Chapter 3.0 and the probable impacts of the present conversion, in Chapter 4.0. There will be a short-term degradation of air quality, primarily as a result of increased PM emissions during the DCO period. Noise levels will be increased slightly due to operation of coal handling equipment. There may also be the possibility of some degradation of water quality if unexpected discharges of untreated wastewater should occur. A long-term monitoring program has been established to detect changes in ground water quality. A minimum of 103 acre-feet of flood storage for the 100-year event has been taken up by required facilities (see Section 4.2.2).

A summary of impacts under the proposed plan and the reasonable alternatives discussed elsewhere in Chapter 2.0 is presented in Section 2.2 (see Table 2-2).

2.4 ALTERNATIVE FUELS

2.4.1 High-sulfur Coal

HWP could select a higher sulfur coal as its primary fuel. Use of coal with a sulfur content greater than 1.5 percent would require installation of a flue gas desulfurization (FGD) system, or scrubbers, to meet current SIP requirements.

A high-sulfur coal typical of one which could be used at Mt. Tom and available from the Northern Appalachian region, would have an average sulfur content of 3 percent. Other coal properties would be similar to the project coal: that is 12,500 Btu/lb; 10 percent ash (80 percent fly ash and 20 percent bottom ash); moisture less than 6 percent; and grindability of 60 minimum. These values are conservative in relation to the mean average coal properties in the West Virginia area, for example (12,750 Btu/lb, 3 percent moisture, 2.2 percent sulfur, 7 percent ash) (McKimmey, 1980).

High-sulfur coal would require the same ash and coal handling facilities as the low-sulfur coal. The installation of an FGD system would, however, require additional facilities and increase storage requirements. FGD systems are primarily used for removal of sulfur oxide gases from flue gases. They are designed on the basis of total flue gas flow rate and are normally located downstream of the precipitators. The current trend in selection of FGD equipment is toward lime, limestone, or double-alkali throw-away systems. A significant amount of waste sludge is produced by these systems. At the present, there is no ready market for large-scale utilization of the by-product sludge. The FGD sludge is therefore a waste product which must be disposed of in an environmentally acceptable manner.

Lime, limestone, or double-alkali materials would require transportation, handling, and storage facilities. Train shipments would be the most likely transportation means; a separate siding would be required. Handling would consist of unloading hoppers from the shaker house, lime feeders, two transfer houses, and two covered conveyors. Two storage silos would be needed to protect the material from precipitation.

Other required processing equipment would include a thickening tank, additive slurry tank, a recycle tank, an additive storage tank, three scrubbers, and three 25-foot diameter tanks.

FGD sludge disposal would consist of three principal operations (Michael Baker, Inc., 1979): processing, transportation, and disposal. Processing would involve various methods of changing the characteristics of the raw sludge for transportation and disposal. Processing methods could consist of forced oxidation, thickening/dewatering (vacuum filtration or centrifuge), or fixation/stabilization (mixing with fly ash, soil, fly ash and lime, or calcilox). Transportation to the disposal site could be accomplished by rail, barge, pipeline, truck, or conveyor depending on location. Practical disposal alternatives are either wet disposal (ponding) or dry disposal (landfill).

An FGD system for the Mt. Tom generating station would produce approximately 200,000 tons per year of wet sludge and cost an additional $18.125 million (based on $125/kw for FGD systems) (McKimmey, 1980). This sludge would add to the waste disposal problem because the by-product is not expected to be marketable. In addition, 28,000 tons of limestone would be required. The resulting sulfur emissions would equal approximately 0.5 $lb/10^6$ Btu, which is below the current 1.21 $lb/10^6$ Btu requirement.

Several programs are underway to develop dry FGD systems. Three methods appear to hold promise of extensive commercial use in the utility market in the near future. Two of these methods, the Shell/UOP method and the activated carbon method, eventually are expected to provide 90 percent sulfur dioxide removal and up to 70 percent nitrogen oxide removal at a cost that is competitive with the more conventional wet FGD systems. The advantages of these methods are substantial: water consumption is only a small fraction of that for conventional wet methods; there is a partial regeneration of the absorbent which cuts down on waste disposal; and the end product, sulfur, is marketable. Unfortunately, these methods are in development stages and are not commercially available nor have they been proven reliable (Jahnig and Shaw, 1981).

A third method, utilizing lime as an absorbent, is presently being installed in a new 414 MW lignite plant in North Dakota. This method combines particulate control with SO_2 control. As with the other two dry methods, water consumption is drastically reduced (Reisinger and Gehri, 1979). However, this method does not regenerate the absorbent nor does it produce a readily marketable by-product. The wastes are more manageable than those in the conventional wet FGD processes, however. Until this system is in full operation and reliability and operational costs can be assessed, this method must also be considered unproven and therefore not an economically sound alternative for HWP. Thus, only the wet FGD systems can realistically be considered.

2.4.2 Refuse-derived Fuel

Refuse-derived fuel (RDF) involves the recovery of useful energy from the combustion of solid waste. RDF can consist of municipal, commercial, and industrial waste materials that are generally shredded and void of ferrous materials (removal of non-combustable material increases the Btu value and results in less equipment abrasion). Geographic variation in refuse composition results in very minor variances. However, the composition of municipal wastes at a given location varies fairly widely in both the short and long term (seasonal). Estimates of the typical seasonal variations in heating value include a ±6 percent variance in total heat available from refuse over a year. Based on available data, RDF can be assumed to have an average heating value of 5,000 Btu per pound. RDF is considered to be a low-sulfur, high-ash fuel.

In the analysis of RDF for Mt. Tom, it was assumed that the garbage and other waste materials would be processed (shredded, metals extracted, etc.) before delivery to the plant. An appropriate method of storing and handling RDF is to stockpile the material in silos (they must be emptied every 2 weeks to prevent spontaneous combustion).

Currently, a Resource Recovery Plant is planned for construction in Springfield, Massachusetts, by the Monsanto Corporation. Most of the area's recoverable solid wastes are expected to be processed and burned at this plant. Transportation distances (approximately 30 miles round trip) from the Holyoke, Easthampton, and Northampton areas will be greater to this plant than to Mt. Tom, but with the city landfills nearing full capacity, city officials are committed to sending materials to the Monsanto Plant (Garcia, 1981, McLalany, 1981, Rundle, 1981, Superneau, 1981, personal communications). The plant is expected to be completed by 1984-1985.

Strict recycling regulation laws are expected to be enacted in Hampden County. The county officials believe that by recovering useful wastes at the source, solid waste collection will be reduced by 75 percent (Johnson, 1981, personal communication). Most of the smaller cities cannot afford the transportation distances to the Monsanto plant and feel that recovery is the best means of reducing their solid waste problems.

Based on the information obtained from the Monsanto plant and the expected recycling regulations, there appears to be insufficient quantities of RDF available to make RDF economically feasible at the Mt. Tom generating station.

2.4.3 Wood/Wood Chips

Wood has about two-thirds the energy content of coal and is an abundant renewable energy source in some areas of the country. The various forms of wood as a fuel range from charcoal to green wood (forest softwood and hardwoods) to wood residues (logging, pulping, barking). Typically, the heating value of wood ranges from 12,100 Btu/lb (charcoal) to 8,800 Btu/lb (wood chips) to 3,000 Btu/lb (wet bark). Moisture content is the major factor affecting heating values. Moisture content for all types of wood ranges from 1.5 percent (charcoal) to 67 percent (bark). The average net heating value is 6,500 Btu/lb for hardwoods and 4,000 Btu/lb for softwoods on an as-received basis. The generally accepted net heating value for air-dried wood (12-15 percent moisture) is approximately 7,500 Btu/lb (Tillman, 1978).

Analyses of eight wood species (softwoods and hardwoods) show wood to be very low in sulfur and ash (Tillman, 1978). The mean sulfur content was 0.013 percent (by weight), and the mean ash content was 1.12 percent. These data indicate that wood is essentially pollution free, although wood combustion requires particulate control.

In considering the feasibility and availability of wood fuel for Mt. Tom, it is reasonable to assume a heating value of 7,500 Btu/lb for air-dried wood and an average potential forest density of 40 tons/acre for the northern states (Morey, 1978). Using these values, 600,000 tons/year of wood would be needed to maintain present generating capacity. This amount of wood equates to approximately 15,000 acres/year of forest harvesting.

Wood transportation is a complex, important issue. Various transportation methods are possible, and the costs vary significantly. Energy costs of transportation, as well as other factors (labor, equipment, etc.), affect total costs. Considering the various factors, a comparison of transportation studies indicates an approximate 50-mile limiting radius for economical movement of wood fuels (Tillman, 1978).

Present land use within a 50-mile radius of the Mt. Tom plant indicates this area could not produce the amount of wood or wood waste necessary for the plant to use wood as the sole energy source. Also, production of wood products is considered to be a higher priority use of wood in the northeast (DOE, 1981).

2.4.4 Conservation

Recent studies of conservation (and alternative energy sources) specific to the New England Region include Energy in New England: Transition to the '80's (Katz and others, 1981), and New England Can Reduce Its Oil Dependence Through Conservation and Renewable Resource Development (General Accounting Office, 1981). The first study notes that significant reductions in oil consumption have resulted from energy conservation in all economic sectors. The primary reason has been the sharp increase in energy prices over the past few years. New Englanders have also implemented conservation measures as a means of improving their energy security. A third contributing factor has been the Federal, state, and local energy conservation programs which have provided information, technical assistance, and financial incentives. In the latter study, it was concluded that in spite of present conservation efforts, and increased use of coal and nuclear power, New England's oil consumption for electrical generation will still be significant in the year 2000, and could possibly increase over present usage. Implementation of conservation measures that are feasible, socially acceptable, and cost effective could reduce the region's oil consumption for power generation by about 27 percent. The study notes, however, that the present bureaucratic and regulatory framework is not conducive to implementation of aggressive conservation measures (and renewable resource development), and that a more unified regional effort will be required to bring about significant further reductions in oil consumption.

DOE also recognizes that the national objective of minimizing the overall consumption of oil and natural gas cannot be achieved by the implementation of ESECA and FUA alone. The limited authority of the act to encourage the use of alternate energy sources in utility boilers means that there is a considerable potential role for actions outside of the authority of DOE (alternative technologies and conservation) to contribute to reaching the goal of reducing reliance on oil and natural gas for generating electricity. In order to assess the potential for alternative technologies and conservation within the Northeast Region, a detailed analysis was performed as part of DOE's Draft NEREIS (DOE, 1981).

In the study, conservation and six energy alternatives to the proposed coal conversion of the units at 42 sites were examined for their potential to displace future oil consumption. In addition to conservation, the following alternatives were considered: solar, wind, small-scale hydroelectricity, coal cogeneration, wood, and geothermal energy. Estimates of the potential of each of the alternatives were introduced into a model to simulate power pool operation for the year 1990. (The three power pools which serve the Northeast Region are the New England Power Pool (NEPOOL), the New York Power Pool (NYPP), and the Pennsylvania-New Jersey-Maryland Interconnection (PJM). The model was used to analyze impacts on electricity generation of potential coal conversions in the region and that of the energy alternatives. The results in each power pool indicated that in 1990 solar, wind, small-scale hydroelectricity, coal cogeneration, and wood resources combined could not achieve an oil savings comparable to that of the potential conversions. Significant additional contributions from conservation, above those indicated by the power pools, would be unlikely. In NEPOOL, it was found that it would be effective to convert all of the potential units to coal and use all of the potential alternatives. As New England is heavily oil-dependent, sufficient benefits would be obtained from both coal conversion and conservation. Additional information and documentation is provided in Section 3.3 and Appendix A of the Draft NEREIS.

2.5 OTHER ALTERNATIVES

2.5.1 Transportation

2.5.1.1 Rail Transportation

Under the present conversion coal is delivered by rail. NUSCO (1981a) has indicated that the coal will be shipped by the following railroads depending on the source: Chessy System, CONRAIL, Delaware and Hudson, and the Boston & Maine.

2.5.1.2 Barge Shipments

Barge shipments are generally the cheapest method of transporting coal if both the mine and end-use plant are located on or near a navigable body of water (McKimmey, 1980). However, the most cost effective means to transport coal to the Northeast is by rail to Baltimore or Norfolk and then by barge along the intracoastal waterway to the New England area. Once in New England, coal barges can travel along the Connecticut River as far as Hartford, Connecticut. From Hartford to the Mt. Tom site, coal would have to be shipped by either railroad or truck.

The major disadvantage of this alternative is the increased coal handling that results from loading and unloading the coal from train to barge to train. Not only are most New England coal unloading facilities in disrepair, but the additional time and expense would tend to make this alternative infeasible.

2.5.1.3 Slurry Pipeline

No commercial coal slurry pipelines presently exist in New England and none are likely to be built soon enough to make this a reasonable alternative for consideration in the Mt. Tom conversion. However, coal transport via coal slurry lines is a future possibility (McKimmey, 1980).

The only existing coal slurry line in the 48 contiguous states transports coal 273 miles from the Black Mesa coal fields in Arizona to the Mojave powerplant in southern Nevada. The 18-inch pipeline delivers 4.8 million tons of coal per year and requires almost one billion gallons of water.

There are many difficult issues associated with coal slurry pipelines. Land use restrictions cause problems in obtaining rights-of-way for long pipelines. The large amounts of water required could be unavailable or have detrimental environmental impacts at the points of intake and discharge. The primary advantage of coal slurry pipelines is their relative insensitivity to inflation and labor strikes, which, in some cases, gives them an economic advantage over other transportation systems.

2.5.2 Plant Modifications

As noted previously, the Mt. Tom generating station was originally designed to burn coal. Areas for coal and waste storage, rail yards, unloading equipment, and the powerhouse were already located onsite. There are no apparent modifications which would provide an environmentally more acceptable alternative for specific equipment or locations of facilities.

A rotary dumper facility could be installed to replace the existing car shaking equipment. With a rotary dumper and special coal hopper cars, the unit train could proceed continuously through the unloading process. The cars are equipped with rotary couplings which enable the rotary car dumper to grasp one car at a time and empty it without removing the car from the train. The rotary car dumper is capable of emptying approximately 30 cars per hour (3000 tons/hour), therefore it would take only 3 to 4 hours to completely unload one unit train (compared to the 14 to 16 hours required with the present system). This procedure would require extensive modification to the rail yards as well as to the shaker house. NUSCO has indicated the costs of these modifications outweigh the benefit of reduced unloading time.

2.5.3 Ash Disposal

2.5.3.1 Offsite Disposal

Offsite disposal of ash is one alternative to onsite storage. The utility (NUSCO, 1981d) believes that environmentally acceptable offsite locations may be difficult to find. While there is much open land in the vicinity of the Mt. Tom generating station, much of it is floodplain, prime farmland or is devoted to recreational uses. This potential difficulty, together with the increased cost of transportation (perhaps as much as $400,000 a year), and purchase and development costs at a site, make this alternative undesirable to NUSCO. Should this method of disposal become necessary, the Commonwealth of Massachusetts, as stated in the MOU, will use its best efforts to assist HWP in acquisition and licensing of disposal sites. It is possible that nearby waste disposal sites might be used temporarily.

2.5.3.2 Sale

Moderate quantities of coal ash (fly ash, bottom ash, and boiler slag) are being used as fill material for roads, construction sites, and land reclamation projects. Coal ash has a lower bulk density than natural soils and thus can be used where foundation bearing strengths constrain the use of a site and rapid consolidation is needed (major settlement takes place in the first year). Coal ash can also be used in a light weight aggregate form as a road stabilizer. Other applications for the use of coal ash are in the production of cement products. It is used as a pozzolan mixed in cement, raw material for cement clinker, concrete blocks for light weight units, and in structural concrete and mass concrete dams. Miscellaneous uses of coal ash (25 percent of the recovered coal ashes) are in oil well cementing, deep mine injection for fire control, mine subsidence control, and non-polluting, anti-skid material for road de-icing. Fly ash has been used as a filter media in wastewater treatment plants (Bern, 1976).

The major problem with recycling and reuse of power plant wastes is that the supply exceeds the demand. Due to the bulk and low material value, the market for ash is very sensitive to transportation costs. Hence the cost of transporting a ton of fly ash 10 miles may greatly exceed its market value. Rail hauling of wastes or secondary materials is penalized in the rate structure set by the Interstate Commerce Commission. In addition, fly ash competes with other types of wastes like steel mill slag and lime and cement plant wastes.

A prospective buyer for fly ash from the Mt. Tom station has been identified who will purchase fly ash if it meets expected characteristics. By March 1983, existing permits require that fly ash be collected in dry form (the form also required for sale); to accomplish this, new facilities will have to be installed and existing ones upgraded. Equipment for separating economizer ash from air preheater and precipitator ash and a vacuum exhauster and dust control equipment would be added and the existing silo would be upgraded. These facilities are estimated to cost $2.7 million; an interim system using the same volume of sluicing water as under the present system will be employed by the summer of 1982. This interim system is expected to cost about $300,000. It is anticipated that the fly ash can be sold for something in excess of $1 per ton. Although such a price would provide an insignificant return on this investment, selling the fly ash on this basis could be less costly than any other disposal alternative except for onsite disposal (NUSCO, 1981d).

The use which HWP feels is most probable for the fly ash from the Mt. Tom generating station is as interim cover in landfills. Because of the potential risk involved in allowing leachate from landfills to percolate to the ground water, standard waste disposal management practice calls for the elimination or containment of the leachate. At most landfills, this practice can be readily achieved with the use of an impermeable and stable cover material (fly ash, for example) placed over landfill cells. The use of fly ash as a cover material is both economical and successful in controlling the leachate from landfills.

Also, while controlling the leachate from landfills, the fly ash itself contributes only minute amounts of leachate (refer to Section 4.2) into the surrounding environment.

The permeability of fly ash is comparable to, or even lower than, permeabilities of other soils used as cover material. Clay has been used as a cover material in the past, but the supply of low-permeability clay is limited in various areas. The adequate supply and availability of fly ash from Mt. Tom station is another advantage for using fly ash as a cover material in municipal landfills.

The use of fly ash as a cover material is not a new issue in Massachusetts. Towns throughout the eastern portion of Massachusetts have been using fly ash as a cover material, and it has proved economical and effective (NUSCO, 1982a). If the constituents of the ash meet needs of a potential client, all of the fly ash can be sold.

The potential market for bottom ash is likely to be related to specific, short-term construction projects for which the bottom ash may need to be promptly available to a purchaser. Potential uses include structural fill and landfill cover material. Though there is little sensitivity to the bottom ash characteristics, there is not a well-defined market. Even if the bottom ash can be sold, it would first be wet sluiced to settling basins before being excavated; no significant new investment or equipment would be needed to facilitate its sale (NUSCO, 1981d).

2.5.4 Early Retirement

One alternative available to NU is early retirement of the Mt. Tom facility. As noted in Section 2.2, the early retirement option is available to the utility whether or not an NOE is issued. Since Mt. Tom provides only 2.2 percent of NU system output, this is a reasonable alternative. There are, however, several interrelated issues to be considered before this alternative is adopted. These include the future of nuclear power, the level of foreign oil consumption, and the level of utility generating reserves.

New England has relied heavily on development of nuclear power to meet its projected energy growth demands. Since the Three Mile Island incident, the future of nuclear power has become increasingly uncertain. NU's conservation scenarios have been based in large part on the assumption that Millstone Nuclear Station Unit 3 will be on line by 1986. Should the startup of this and other nuclear plants in the New England Power Pool be delayed there could be serious reductions in reserve margins by 1983-1984 (McKimmey, 1980).

If the reserve margin for the New England Power Pool should decline to 14.5 percent by 1983/84, retirement of any power plant within the member's systems would have to be carefully considered (McKimmey, 1980).

2.6 SUMMARY OF ALTERNATIVES

In the preceding sections of this chapter reference has been made to impacts of the various alternatives. A comparison of alternative actions is presented in Table 2-2.

Chapter 4.0 considers construction and operation impacts in detail, with emphasis on significant issues.

2.7 SUMMARY OF CUMULATIVE ENVIRONMENTAL EFFECTS

The substantive environmental areas assessed in the Draft Northeast Regional Environmental Impact Statement (NEREIS) (DOE, 1981) are: air quality, water quality, land use, biotic resources, socioeconomics, and health effects (see Section 1.4). The overall analysis indicates that regional cumulative or interactive impacts are likely to occur in only a few of these substantive areas, and that the magnitude of the potential impact is small. The following discussion summarizes briefly the substantive areas where there is a potential for cumulative impact, particularly where the state of Massachusetts or the Boston air quality subregion could be affected (Figure 2-1).

2.7.1 Air Quality

Cumulative impacts on air quality from the combustion of coal at 42 power plants in the Northeast Region could result from (1) plume interaction and integration at the local/subregional level, and (2) long-range transport and the resultant pollutant formation and deposition at the regional level. The predicted cumulative air quality impacts related to the proposed conversions are presented in detail for each subregion in Section 5.1 of the Draft Northeast Regional Environmental Impact Statement (NEREIS) (DOE, 1981). The pollutants with the greatest potential for increased emissions due to coal conversions are PM, NO_x, and SO_2. The air quality analysis in the draft report included a number of assumptions about these criteria pollutants. PM emissions were modeled, including state-of-the-art technology controls that are currently in place or can be retrofitted; consequently, projections associated with conversion to coal did not result in any increase in the PM emission rate. NO_x is of concern at both the local and regional scales. Modeling factors constrain the comparison of the air pollution emission scenario concentrations that were modeled, so emissions of nitrogen oxide are assumed constant under all coal conversion scenarios. An increase in the number of facilities burning coal could result in increases in SO_2 emissions either up to the rates currently allowed by existing Federal and state regulations or to new levels specified by changes in these regulations.. These emissions can, however, be controlled through the application of several tested techniques - flue gas desulfurization systems (scrubbers), burning low-sulfur coal, coal washing prior to combustion. To reflect the appreciation of this type of technology, mitigative scenarios were developed and modeled in addition to the four basic emission scenarios.

The Robert A. McCormack (RAM) Model was used to predict the impacts of emissions from the powerplants at the subregional level. This model, which is used in regional studies by USEPA, is a multiple-source Gaussian algorithm model. The model predicts hourly, 3-hour, 24-hour, and annual average concentrations of gaseous pollutants and small

TABLE 2-2

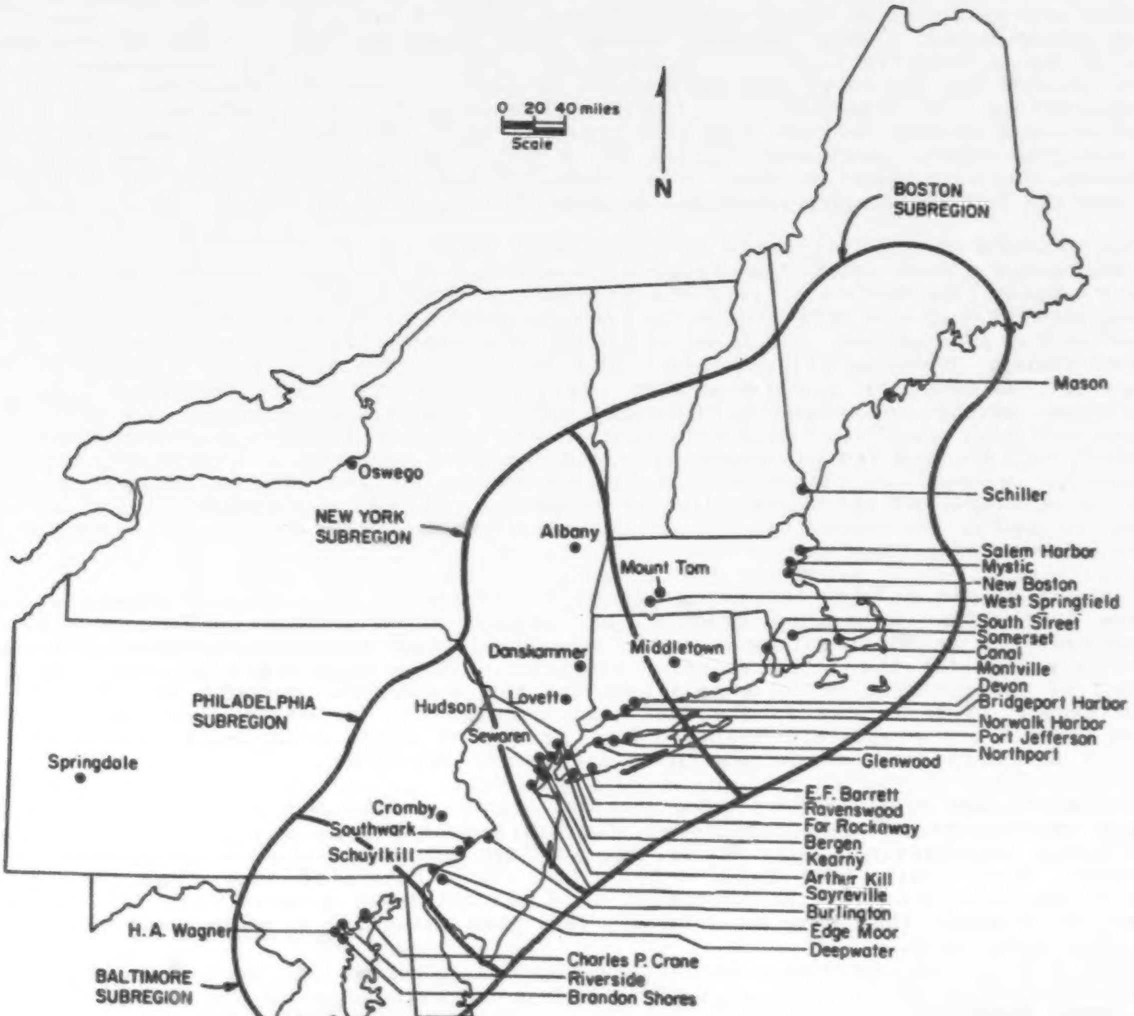
COMPARISON OF ALTERNATIVES

Page 1 of 2

ALTERNATIVE	ACTIVITIES INVOLVED	MAJOR ADVANTAGES	MAJOR DISADVANTAGES	APPARENT FATAL FLAW OF ALTERNATIVE	ENVIRONMENTAL IMPACTS
Action No Action					
Return to Operation on Oil	• Minor Construction	• No increase in environmental impact over plant configuration prior to December 1981.	• Continued dependence on imported oil	• Continued dependence on imported oil	• No long-term change from preconversion conditions.
Voluntary Conversion	• Same as Low-sulfur Coal	• Same as low-sulfur coal	• Same as low-sulfur coal	• None	• Same as low-sulfur coal
Early Plant Retirement	• Plant dismantle	• Positive environmental impacts on local area • Reduced local use of imported oil	• Reduction of system reliability margin • Greater dependence upon nuclear construction • No rate reduction	• Uncertain, but will possibly reduce reserve margins within NE Power Pool, below acceptable limits.	• Cessation of present emissions and discharges. Loss of employment for workers at the power plant.
Fuel Low-sulfur Coal	• Rail yard overhaul • Boiler overhaul • New control equipment • Develop waste disposal system	• Use of low cost fuel • Immediate lowering of rates • DCO will allow funds to be raised for capital expenditures	• Temporary construction impacts • Temporary increase in TSP • Increase in long-term SO2 emission limits	• None	• Short-term construction impacts-slight degradation of water quality increase in fugitive dust. Increase in TSP (temporary) and long-term SO2 increase of noise; potential for ground water contamination.
High-sulfur Coal	• Addition of FGD system to proposed plan • Added storage area needed	• Wider selection of fuel sources • Lower sulfur emissions	• Increased solid waste disposal problems • Much higher costs for installation and operation • Rate reduction may not be possible	• None	• Increased transportation, more construction activity; extra storage facilities needed for lime/limestone and for scrubber sludge. Additional rail traffic. No interim period of increased particulates.
Refuse-derived Fuel	• Modification of railyard in addition to planned action • Modification to fuel handling system in addition to planned action	• Recycles resources • Low sulfur and ash fuel • Reduces burden on local landfills	• Limited supply • Low heat value • Extensive transportation system • Competition will soon exist for RDF	• Not enough in the vicinity to make this feasible	• Decreased need for refuse disposal sites; increase cost of conversion handling; addition of new storage facilities
Wood/Wood Chips	• Redesign of boilers from planned action • Modification of fuel handling equipment	• Renewable resource • Low sulfur fuel	• Extensive transportation system required • Competition with other uses of wood in the area thereby driving up the price of wood • Extensive environmental impact of clearcutting 15,000 ac/yr	• Not enough wood within 50 mile radius for long-term supply	• Extensive destruction of forest habitat; increased transportation requirements and costs; increased storage areas; increased construction activities for storage, handling, operation.

TABLE 2-2 (Continued)

ALTERNATIVE	ACTIVITIES INVOLVED	MAJOR ADVANTAGES	MAJOR DISADVANTAGES	APPARENT FATAL FLAW OF ALTERNATIVE	ENVIRONMENTAL IMPACTS
Conservation	• Public cooperation	• Best alternative for conservation of natural resources • No increase in environmental impacts	• Is not expected to offset load demand to significantly reduce need for the plant • Would still require use of imported fuel unless demand sufficiently reduces in near future.	• Not expected to reduce power	• Increase production of insulating materials, etc. (with environmental and energy requirements)
Transportation					
Railroad Transportation	• Utilize trains for coal transportation	• Rail network in operation already for this use • Minimum handling	• Rail transport is generally more expensive than barge • Susceptable to strikes	• None	• Slight increase in train traffic with attendant emissions and fuel consumption
Barge Transportation	• Utilize barge transportation as much as possible	• Barge transportation is inexpensive if plant is near navigable water	• Extensive handling involved due to limited availability of waterways • Coal ports need improvement	• Increased cost without an offsetting benefit because of distance from water	• Slight increase in potential for water pollution from oily waste or coal spills
Coal Slurry Pipeline Transportation	Utilize pipeline to transport coal from mine to plant	• Low transportation cost • Low susceptability to strikes • Low environmental impacts	• Pipeline does not exist • Technology not proven • Construction of pipeline would be several years and very expensive	• Pipeline not available in foreseeable future	• Impacts to land use, biota, water quality, labor use from construction activity
Waste Disposal					
Onsite Waste Disposal	• Development of ash disposal ponds onsite	• No transportation need • Lower cost than transporting offsite • No site acquisition necessary	• Location in floodplain • Possible seepage into Connecticut River	• None	• Reactivation of previously used disposal areas; possible ground water contamination; developmen of new areas would require use of prime farmland
Offsite Waste Disposal	• Selection and use of a waste disposal site near plant, increase in traffic	• Removes wastes from floodplain and immediate vicinity of Connecticut River	• Extensive transportation system required • Development and acquisition of site required • More expensive than others	• None	• Possible need for new site (compared to use of existing facility) with destruction of habitat, change in land use plants, water quality degradation, increased transportation and cost. Existing storage areas may be used initially.
Sale of Solid Wastes	• Sell ash as raw material increase in traffic	• Most economical method • Minimizes disposal impacts	• Low economic value • Competitive market • Unfavorable rail transport rate regulations	• Steady market is questionable	• Slight increase in transportation requirements
Facility					
Rotary Dumper	• Replacement of shaker house with rotary dumper	• Reduced noise level • Reduced train unloading time	• Higher capital costs over planned action	• None	• More construction activity; change in siding layout; increased cost


0 20 40 miles
Scale
N
BOSTON SUBREGION
Mason
Oswego
Schiller
NEW YORK SUBREGION
Albany
Salem Harbor
Mystic
New Boston
West Springfield
Mount Tom
South Street
Somerset
Canal
Montville
Danskammer
Middletown
Devon
Bridgeport Harbor
PHILADELPHIA SUBREGION
Hudson
Lovett
Norwalk Harbor
Port Jefferson
Northport
Sewaren
Glenwood
Springdale
E.F. Barrett
Ravenswood
Far Rockaway
Bergen
Kearny
Cromby
Southwark
Schuylkill
Arthur Kill
Sayreville
Burlington
Edge Moor
Deepwater
H. A. Wagner
Charles P. Crane
Riverside
BALTIMORE SUBREGION
Brandon Shores

Source: DOE, 1981.

Figure 2-1 Combustion Assessment Region and Four Air Quality Subregions.

particulate matter. Because of the large number of sources analyzed in the subregion, and because a large number of receptors are incorporated into the analyses, the RAM model was the most applicable model available for use at the start of the anlaysis in 1979. The resulting predictions may not be numerically accurate, as the RAM model does not include the effects of terrain and uses a single source meteorological data for each subregion; however, the modeling should reasonably indicate trends in pollutant levels. In all cases, the assumptions used in the model were conservative in order to generate the worst case predictions of air quality impacts related to the proposed action.

The projected incremental changes in air quality associated with each of the modeled emission scenarios must also be viewed within the context of the ambient baseline conditions in the subregion. In the Boston subregion, violations of the primary SO_2 standards are predicted to occur only under the Coal SIP air quality scenario (see Table 1-1 for description). The violation would occur near the isolated Mason Generating Station in Maine (see Figure 2-1). Further, SO_2 emissions limitations were assessed for the New Boston and Mystic generating stations as part of a mitigative analysis. Under the scenario limiting the emissions from the New Boston plant, the predicted 24-hour SO_2 increase is considerably reduced from that expected under the Coal SIP. Lowering of emissions from the Mystic plant also results in a reduction in predicted 24-hour SO_2 concentrations, but to a lesser degree. The results of the analysis are described in greater detail and the full results are presented in Section 5.1.3.3 of the NEREIS (DOE, 1981).

The analysis of the long-range transport and deposition of pollutants at the regional scale was accomplished using the Advanced Statistical Trajectory Regional Air Pollution (ASTRAP) Model (see Section 5.1.4.2 and Appendix M; (DOE, 1981). This model estimates the long-term averages of SO_2 and sulfate concentrations, and long-term accumulations of both wet and dry deposition. It is important to note that ASTRAP, like other long range transport models, predicts wet deposition of total sulfur, the vast bulk of which is sulfate and not rainfall pH. While sulfate appears to be the major contributor to acid precipitation, nitrate is almost as important during the winter months. At this time, however, there is insufficient understanding of the chemical forms and concentrations of atmospheric nitrate and the processes by which they are produced in the atmosphere and subsequently removed to permit meaningful simulations of the long-range transport of nitrogen compounds and their deposition as nitrates. ASTRAP simulations of the relative increase of sulfur deposited by wet processes are thus used instead to estimate the relative increase of acid precipitation.

Analysis of the modeled long-range transport associated with each emission scenario indicates that sulfur deposition over all of eastern North America would increase by approximately one percent for the scenario with the largest emission increment, and correspondingly less for the other emission scenarios. It is worthwhile to note that less than half of the increase in total emissions for the worst-case scenario is deposited in the Northeast. This is due to the fact that most of the candidate plants are located along or near the northeastern seaboard and prevailing winds indicate that much of the time stack emissions are transported out to sea before deposition.

The study also considered specific receptor locations downwind of the source region. Of the three receptor locations considered, the Adirondack Mountains of New York, areas of central Maine, and southern Nova Scotia, the smallest increases were the Adirondacks, and the largest, Nova Scotia (see Table 2-3). The study concluded that while the overall effects in sensitive areas of the Northeast were several times greater than for the subcontinent as a whole, they were considerably less than those due to emissions from regions outside the study area.

2.7.2 Water Quality

As a result of the air quality modeling of the long-range transport of sulfates and nitrates from coal combustion, the NEREIS concluded that the increase in sulfur deposition in areas downwind of the study region associated with the long-range transport of pollutants would result in a pH change of less than 0.03 in receiving waters. While the contribution of nitrogen oxide emissions to acid deposition is currently not known, the effects are believed to be less than for sulfur. A consideration of the buffering properties of water bodies that might be affected leads to the conclusion that the proposed action (conversion of 42 Northeast Region powerplants to coal) alone is unlikely to cause significant acidification in surface water.

TABLE 2-3

ESTIMATED CURRENT ANNUAL AVERAGE CONCENTRATIONS AND CUMULATIVE DEPOSITION OF SULFUR, AND PERCENT INCREASE EXPECTED UNDER MODIFIED COAL SIP

Receptor Location	SO_2 ($\mu g/m^3$)	Sulfate ($\mu g/m^3$)	Wet Deposition ($g/m^2/yr$)	Dry Deposition ($g/m^2/yr$)
Adirondacks (44.5 N, 74 W)	12.0(2)[a]	5.1(1)	1.4(1)	0.9(2)
Central Maine (46.5 N, 70 W)	7.0(4)	4.0(2)	1.2(2)	0.6(3)
Southern Nova Scotia (44 N, 65.5 W)	3.5(5)	2.4(4)	1.1(4)	0.3(6)

---

[a] Numbers in parentheses indicate percent increase expected under Modified Coal SIP.

Source: DOE, 1981.

2.7.3 Land Use

The increase in coal combustion and the associated solid waste associated with the use of pollution control technology could present a cumulative impact in terms of the availability of waste disposal sites in the region. Solid waste disposal problems are developing in many areas of the Northeast even before utility waste streams are considered. Some areas face considerable difficulty in locating sites for routine municipal solid waste disposal or for disposal of various industrial wastes. Overall for the Northeast Region, based on a projected 1990 population of 53,518,000, a residential and commercial waste quantity of 47,180,000 tons per year, and an ash quantity of 4,717,000 tons per year, conversion to coal of all the proposed facilities would result in ash generation amounting to a potential increased municipal waste burden of 10 percent. Competition between ash and municipal waste would be reduced, to the extent that these two wastes could make compatible use of the same landfill, and to the extent that ash could be used as a cover for municipal waste.

2.7.4 Biotic Resources

Potential ecological impacts associated with combustion emissions and waste disposal are anticipated to be significant mainly on a site-specific level. Outside site vicinities, such as those areas associated with acid deposition, the pH change of less than 0.03 in receiving waters should have negligible impact on terrestrial and aquatic ecology.

2.7.5 Socioeconomics

Coal used in the 42 power plants assessed in the Northeast Region document would originate in the northern Appalachian coal supply region. If all 42 conversions were to occur, approximately 38.3 million tons of coal would be consumed annually. After other market adjustments, the annual production of the supply region is predicted to increase about 4 percent as a result. This increase is considered within the normal levels of activity in the region. Similarly, transportation networks are considered to have adequate capacity to provide necessary levels of service. Demand for coal would increase substantially in the Northeast Region. Nearly 100 percent of the anticipated demand for coal in Massachusetts would be for coal conversion by utilities.

Powerplant conversions would have only site-specific socioeconomic effects from plant conversion and operation. In some portions of the study region, industrial growth could be curtailed as a result of PSD increment consumption by several powerplants in the same general vicinity. This would not be expected to occur in the Boston subregion, however.

It is unlikely that the projected increase in acid deposition associated with the conversions would result in losses to the tourist industry in the deposition region; other effects to the region are not possible to quantify.

2.7.6 Health Effects

The increase in mining activity and coal movement stemming from the 4 percent increase in coal demand will result in a slightly higher probability of accident-related fatalities and injuries at the mine sites and along the transportation routes.

In the areas surrounding the facilities, the public health effects of concern are associated with increased levels of SO_2, NO_x, PM, and radionuclides. Generally, there has been a declining trend in SO_2 emissions (the major source of which is coal combustion) due to the enforcement of relatively strict standards for old facilities, and even more stringent controls for new sources. In particular, SO_2 levels in the Northeast have declined in recent years and are currently well below the NAAQS (Section 5.6.3; DOE, 1981). On the basis of the NAAQS and published information which indicates that SO_2 is innocuous relative to other pollutants, it is fair to say that SO_2 concentrations per se do not present a serious problem with regard to health effects. The main concern is over the conversion of SO_2 to sulfates, currently suspected of causing health effects when associated with particulates.

As mentioned previously, the incremental increase in sulfur resulting from the potential fuel conversions over the entire region is on the order of one percent, and increases in sulfate deposition vary from 2 percent to 5 percent, depending on the receptor location. In view of these relatively small increments in sulfur and sulfate deposition, it is doubtful that the proposed conversions would significantly worsen the existing sulfate problem. The 1972 existing sulfate levels in the northeastern United States, 13.6 $\mu g/m^3$ in urban air and 10.2 $\mu g/m^3$ in nonurban air (EPA, 1975), already exceed some of the threshold values described in the literature. Therefore, any adverse health effects would appear to be primarily the result of existing sulfate levels, rather than of any increase in sulfate levels expected as a result of the conversions. In any event, increases in health effects attributable to small incremental changes in air quality resulting from the proposed action are not quantifiable at present.

The effect of the proposed fuel conversions would be to increase current nitrogen oxide emissions in the Northeast Region by roughly 2 percent. With increasing use of coal, the nationwide trend of increased nitrogen oxide emissions is likely to continue unless appropriate control technologies are developed (Sections 3.2.2.3 and 5.6.3; DOE, 1981). It would be impossible to anticipate or predict a change in health effects resulting from such a small (2 percent) incremental increase in nitrogen oxide levels; however, considering the general trend of increased nitrogen oxide emissions and the fact that nitrogen oxide levels already are high enough to cause concern, the incremental nitrogen oxide emissions should be investigated further.

Overall particulate emissions exhibit a declining trend and are projected to decline further (Mitre Corp., 1978). Unlike emissions of sulfur oxides, particulate emissions originate from a variety of sources, including the structural materials industry (crushed stone), the iron and steel industry, and several other non-energy sources; these account for most of the particulate emissions. Utilities and boilers, which constituted only about 30 percent of the particulate emissions in 1975, are expected to contribute even less in the future, because of the installation of electrostatic precipitators and baghouses on boilers. This would lead to even fewer PM standards violations, which already are rare. Although current concern is over fine respirable particulates, and not over total PM, the latter serves as a good index and there are documented studies (Ferris and others, 1971, 1973, 1976) that indicate that present PM standards provide adequate protection for public health. Thus, there are no anticipated adverse health impacts from the PM increment generated by the proposed fuel conversions alone.

At present, radionuclides, trace elements, and polycyclic organic matter are not covered under the Clean Air Act regulations, and there is concern over the possibility that these pollutants, which are emitted from coal fired power plants, may cause adverse health effects. Unfortunately, plant-specific and regional exposure information is not available for these emissions. Consequently, the health effects assessment for these materials has been conducted using generic exposure information, where it exists. In general, the emission levels anticipated for these materials are not expected to cause adverse health effects. A more detailed discussion of health effects found in Appendix E of the Draft Northeast Regional Environmental Impact Statement (DOE, 1981) is reprinted as Appendix A of this document.

3.0 AFFECTED ENVIRONMENT

3.1 GEOLOGY AND SOILS

3.1.1 Regional Geologic Setting

The Mt. Tom generating station is on the west bank of the Connecticut River immediately south of the water gap between the Mt. Tom and Mt. Holyoke Ranges. The river valley is generally broad, with uplands on either side composed of metamorphosed Paleozoic rocks. The valley itself roughly parallels the long axis of a Triassic basin in which terrestrial sediments were deposited and which was the site of lava flows and some volcanic activity. The Mt. Tom/Mt. Holyoke Ranges have withstood erosion because they are capped by one of these lava flows.

The area has been covered by continental ice sheets during several periods of glaciation over the last million years. The glaciers have left striations and grooves on the Triassic and Paleozoic bedrock in the area and have transported large and small boulders (erratics) and soil materials from great distances. The Connecticut Valley is marked also by many depositional features related to its glacial history. During the last retreat of continental glaciers, glacial lakes were formed along many of the major streams including the Connecticut River. Clays and other fine-grained sediments were deposited in these lakes, with coarser materials deposited as deltas where rivers entered the lakes. The glacial deposits have helped to make much of the area an excellent farming region, a factor of special significance when compared to the typical upland areas which are rock strewn with glacial erratics and are difficult to farm.

The Connecticut Valley is somewhat narrower in the area of the water gap adjacent to the plant than it is to the north and south. Here the Triassic sediments and lava are close to the surface or form outcrops, and the glacial deposits are more restricted. The southern part of the plant site is, however, used as a corn field, and the area on the bluff across the river is also a farming region devoloped on the glacial deposits.

3.1.2 Site Geology

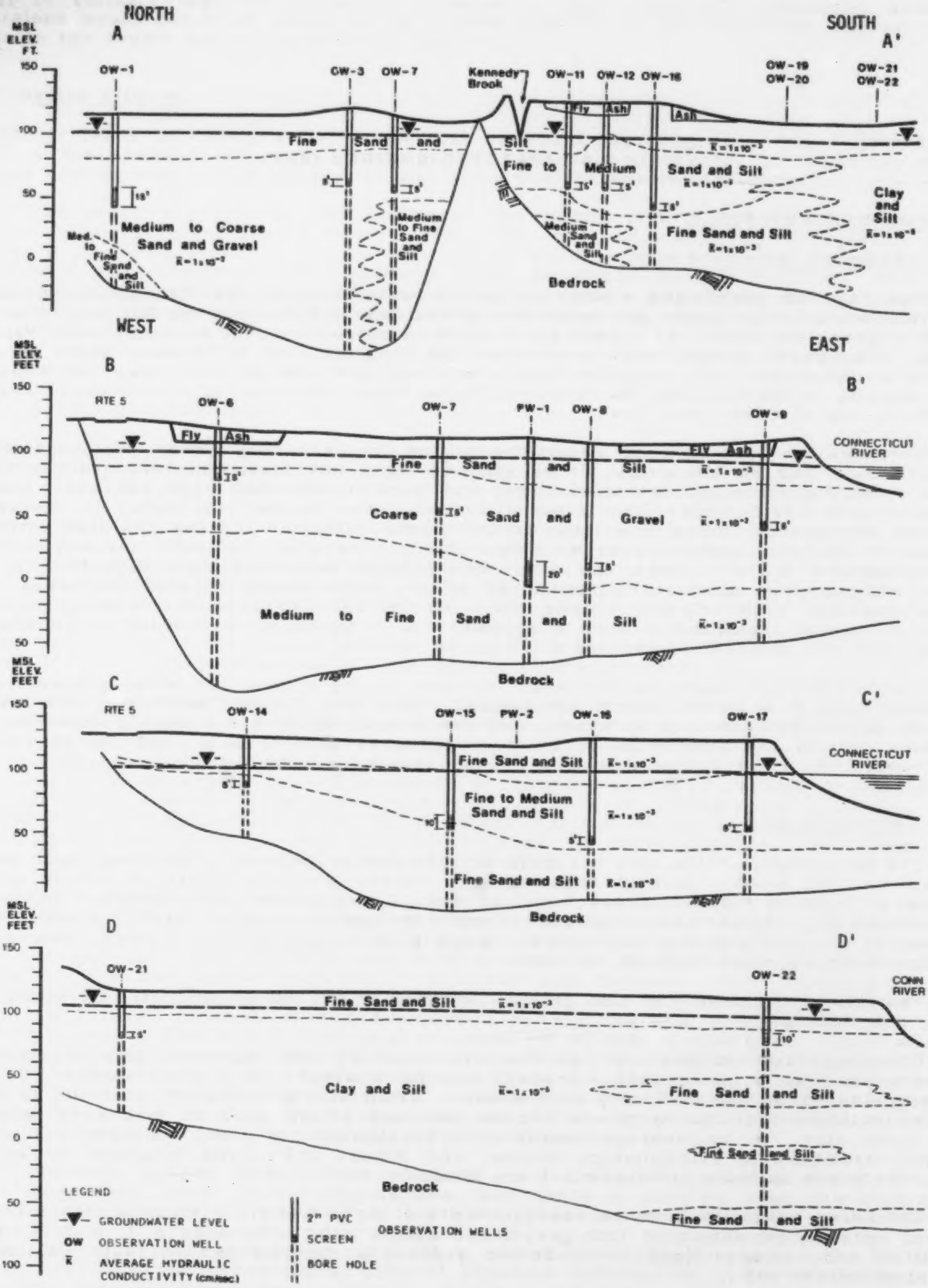
The topography at the site has been largely altered because of previous coal burning activities. Ash ponds, landfill deposits, and borrow pits are scattered across much of the area. South of Kennedy Brook, some 15 acres is considered prime farmland and is used for a cornfield. Elevations range from about 140 feet in some of the fill areas to about 100 feet at the mouth of Kennedy Brook. Deposits of bottom ash and fly ash, averaging 10 feet in thickness cover much of the site.

The following summary of site geology is based on the study conducted by Gibbs & Hill (1981) for NUSCO.

Unconsolidated sediments within the site boundary are separated into northern and southern sections by a buried east-west trending bedrock ridge which bisects the plant property and crops out at four places onsite. Grain size distribution analyses of boring samples indicate that the northern section consists of mixtures of fine sand and silt, with little clay, to an average depth of approximately 40 feet. Figure 3-1 depicts general stratigraphic relationships onsite, and Figure 3-2 shows locations of wells on which the cross sections of Figure 3-1 are based.

Extending downward from an average depth of 40 to 130 feet, there occurs a layer of coarser material consisting of fine gravel and coarse sand with some medium to fine sand and little silt. Connecticut River bottom sediments opposite the northern section also consist of coarse sand.

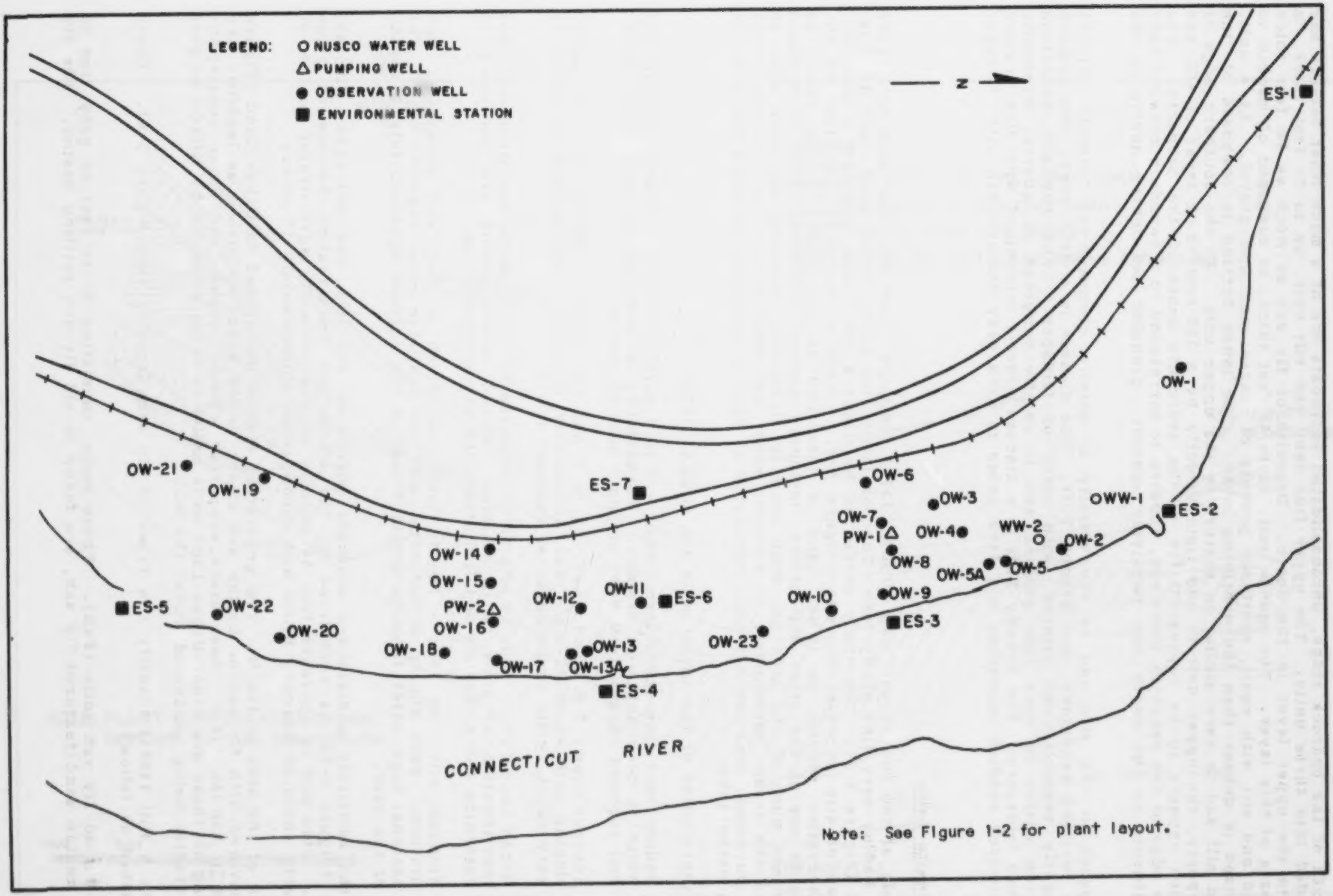
Underneath the above layers, in the area just north of the bedrock ridge, there occurs a discontinuous horizon of fine sand and silt, which varies in thickness from 0 to 100 feet.


NORTH
SOUTH
A
A'
MSL ELEV. FT.
150
100
50
0
OW-1
OW-3
OW-7
Kennedy Brook
OW-11
OW-12
OW-16
OW-19
OW-20
OW-21
OW-22
Fly Ash
Ash
Fine Sand and Silt
K̄=1×10⁻³
Fine to Medium Sand and Silt
K̄=1×10⁻²
15'
5'
Medium to Coarse Sand and Gravel
K̄=1×10⁻²
Med. to Fine Sand and Silt
Medium to Fine Sand and Silt
Medium Sand and Silt
Fine Sand and Silt
K̄=1×10⁻³
Clay and Silt
K̄=1×10⁻⁵
Bedrock
WEST
EAST
B
B'
MSL ELEV. FEET
150
100
50
0
50
RTE 5
OW-6
OW-7
PW-1
OW-8
OW-9
Fly Ash
Fly Ash
CONNECTICUT RIVER
Fine Sand and Silt
K̄=1×10⁻³
Coarse Sand and Gravel
K̄=1×10⁻²
5'
20'
Medium to Fine Sand and Silt
K̄=1×10⁻³
Bedrock
C
C'
MSL ELEV. FEET
150
100
50
RTE 5
OW-14
OW-15
PW-2
OW-16
OW-17
CONNECTICUT RIVER
Fine Sand and Silt
K̄=1×10⁻³
Fine to Medium Sand and Silt
K̄=1×10⁻³
5'
10'
Fine Sand and Silt
K̄=1×10⁻³
Bedrock
D
D'
MSL ELEV. FEET
150
100
50
0
50
100
OW-21
OW-22
CONN RIVER
Fine Sand and Silt
K̄=1×10⁻³
5'
10'
Clay and Silt
K̄=1×10⁻⁵
Fine Sand and Silt
Fine Sand and Silt
Fine Sand and Silt
Bedrock
LEGEND
GROUNDWATER LEVEL
OW OBSERVATION WELL
K̄ AVERAGE HYDRAULIC CONDUCTIVITY (cm/sec)
2" PVC
SCREEN
BORE HOLE
OBSERVATION WELLS

Source: Gibbs & Hill, 1981.

See Figure 3-2 for Location of Wells.

Figure 3-1. Stratigraphic Relationships of Onsite Quaternary Deposits.


LEGEND: ○ NUSCO WATER WELL
△ PUMPING WELL
● OBSERVATION WELL
■ ENVIRONMENTAL STATION
N
ES-1
OW-1
OWW-1
ES-2
WW-2
OW-2
OW-3
OW-4
OW-5
OW-5A
OW-6
OW-7
PW-1
OW-8
OW-9
ES-3
OW-10
OW-23
ES-7
OW-11
ES-6
OW-12
OW-13
OW-13A
ES-4
OW-14
OW-15
PW-2
OW-16
OW-17
OW-18
OW-19
OW-21
OW-22
OW-20
ES-5
CONNECTICUT RIVER

Note: See Figure 1-2 for plant layout.

Figure 3-2. Location of Wells and Environmental Stations for Hydrogeologic Study.

South of the bedrock ridge, unconsolidated sediments are of a much finer texture and are divided into three units. The upper fine sand and silt unit, up to 35 feet thick, is similar to the upper layer in the north. Deposits of fly ash as much as 10 feet thick cover parts of this layer. The middle unit, 25 to 60 feet thick, is composed of medium to fine sand and silt with small, scattered pockets of coarse sand and gravel. As a unit, this horizon is denser than the overlying layer. The lower horizon is composed of fine sand and silt and is very similar in texture to the upper unit. At the southern edge of HWP property, the upper unit is underlain directly by a 130-foot thick layer of silt and clay which appears to be representative of the sediments south of the property. The southern edge of the property therefore, appears to correspond to a boundary between very fine sediments to the south and relatively coarser, granular sediments underlying the site.

Bedrock at the site and in the vicinity is chiefly composed of Triassic Holyoke Diabase, Portland Sandstone, and Granby Tuff. The diabase is a dark gray, fine-grained rock slightly vesicular and jointed, with veins of feldspar. The Portland Sandstone varies from coarse to very fine grained and is chiefly composed of quartz, muscovite flakes, and feldspars. The Granby Tuff is a diabase breccia intermixed with fine-grained to gravel-sized reddish sandstone and dark green to dark gray diabasic ash with feldspar veins.

3.1.3 Onsite Soils

Study of the county soil map (USDA, 1978) indicates there are four main soil types onsite: Hadley very fine sandy loam, Suncook loamy fine sand, Urban Land, and Winooski silt loam (Figure 3-3). The study conducted by Gibbs & Hill (1981) provides a more detailed map of site surficial deposits (Figure 3-4). Much of the area classified by the soil conservation service as Urban Land is identified in the Gibbs & Hill study as belonging to one of the other soil series, including several additional acres of Winooski soils. Since much of the area has been used for industrial purposes for more than 20 years and the areas, particularly of Winooski soils, are discontinuous or used for roads or other purposes, they are not here considered as part of the prime farmland discussed in following paragraphs.

Characteristics of the onsite soils are (USDA, 1978):

1) Hadley very fine sandy loam (HbB) - 3 to 6 percent slopes. Gently sloping soil which is deep and well drained. Permeability is moderate to moderately rapid. Soil reaction ranges from very strongly acid to neutral.

2) Suncook loamy fine sand (Su) - 0 to 5 percent slopes. Nearly level to gently sloping soil which is deep and excessively drained. Permeability is rapid or very rapid, while available water capacity is low.

3) Urban Land (Ub) - Soils so altered or obscured by urban works and structures that identification of soils is impossible. Onsite investigations are necessary to determine the potentials and limitations for any proposed use.

4) Winooski silt loam (Wo) - Nearly level soil which is deep and moderately well drained. Permeability is moderate, with the available water capacity high. The seasonal high water table is within 2 feet of the surface approximately 5 months of the year.

Of the relatively undisturbed southern portion of the site, one soil type, Winooski silt loam (Figure 3-3), is considered by the USDA Soil Conservation Service as prime farmland. This soil is approximately 44 percent of the primarily agricultural portion of the property south of Kennedy Brook and encompasses approximately 15 acres.

Much of the area of the Mt. Tom generating station designated as Urban Land (Figure 3-3) is covered with fly and/or bottom ash either in old ponds or placed as landfill. As discussed in Section 3.4.2, these areas supported willows, aspen, and other vegetation. Information on these and other Urban Land soils onsite is being collected by NUSCO as part of their studies being conducted under the MOU.

Gibbs & Hill (1981) identify two types of fly ash deposits (see Figure 3-4). These are described as follows:

1) Buried fly ash soils (FaB). These soils, consisting of 10 feet of grey fine to medium sand-textured fly ash, are found in old fly ash settling basins. The fly

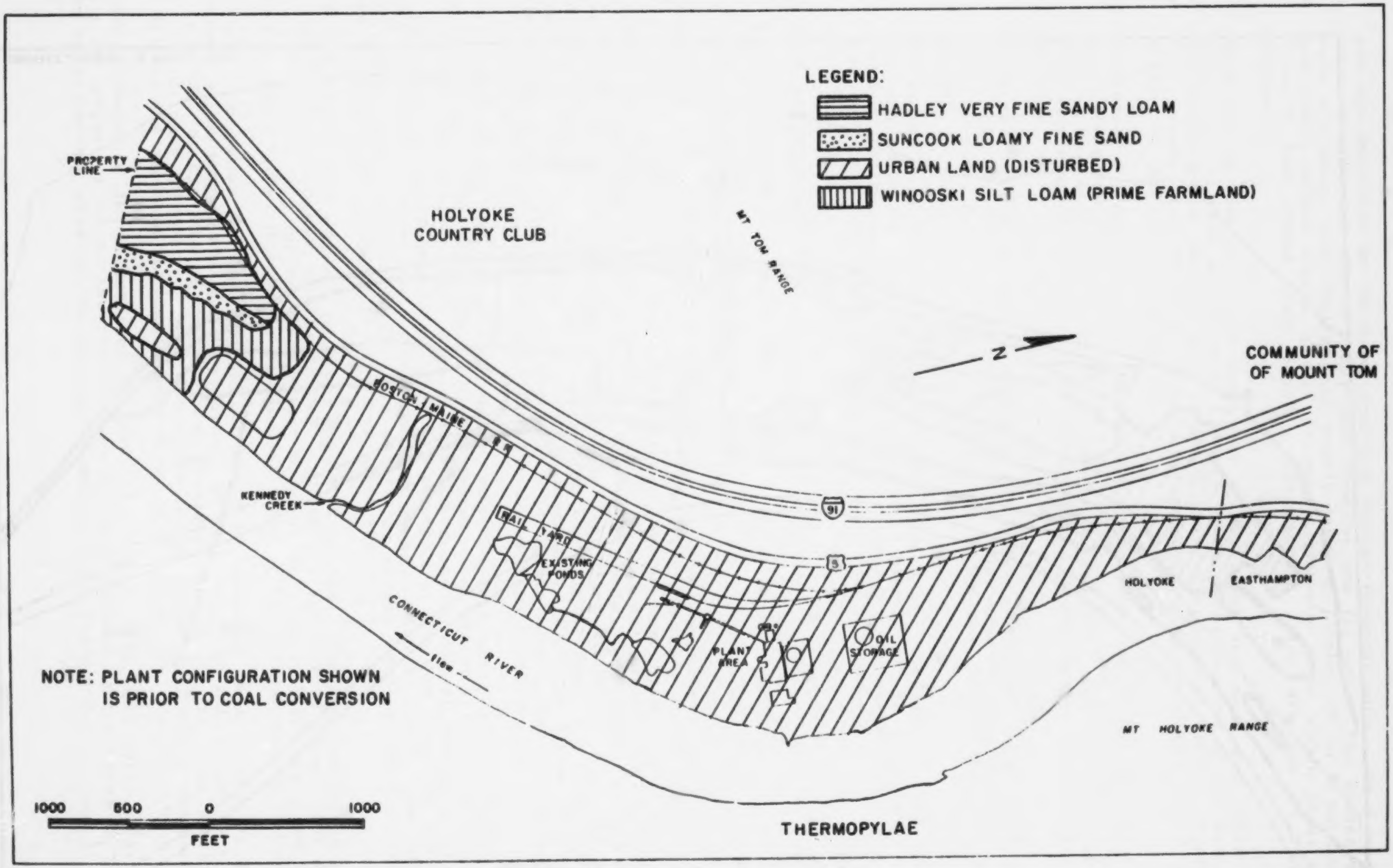
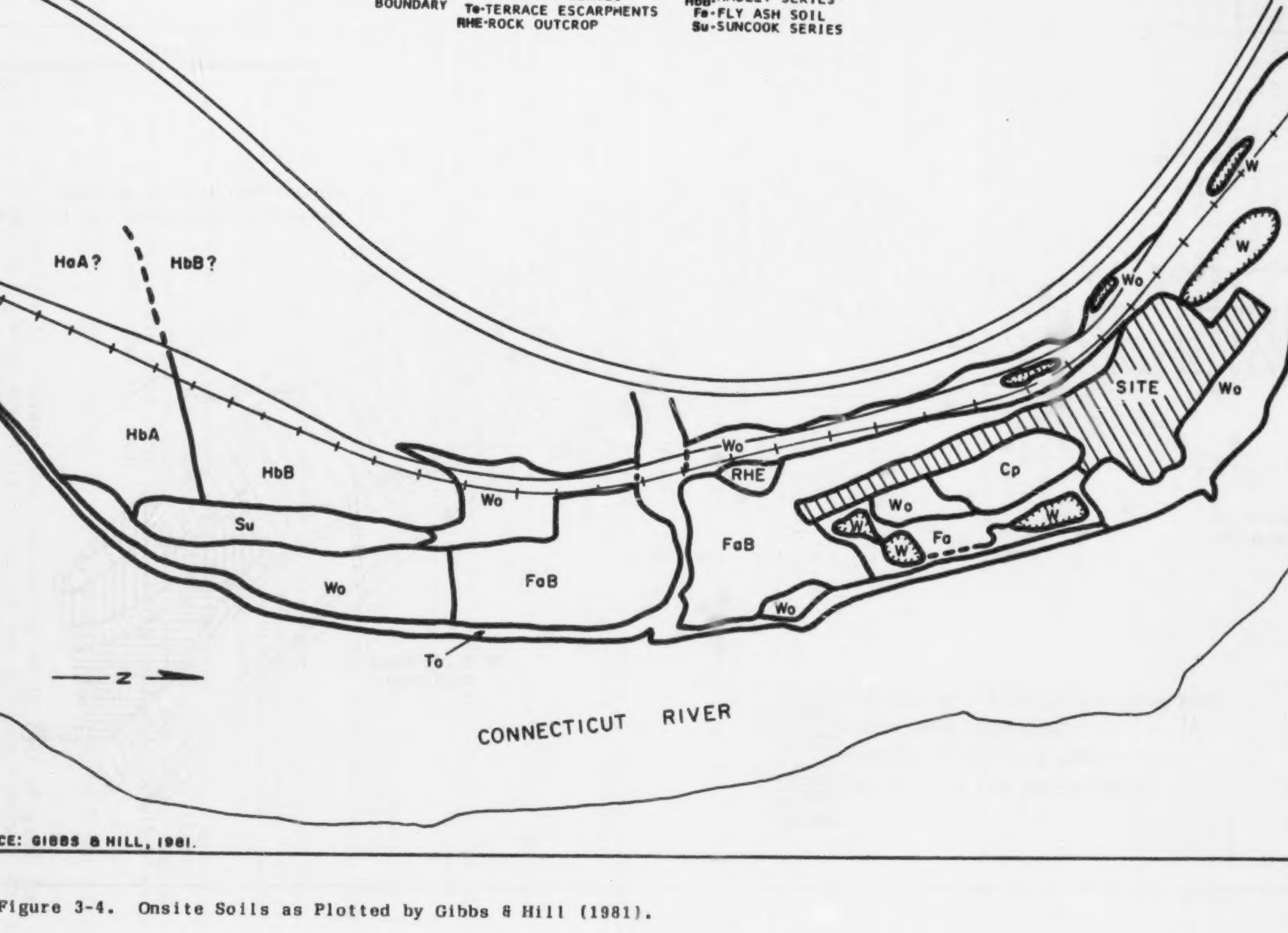

LEGEND:
HADLEY VERY FINE SANDY LOAM
SUNCOOK LOAMY FINE SAND
URBAN LAND (DISTURBED)
WINOOSKI SILT LOAM (PRIME FARMLAND)
PROPERTY LINE
HOLYOKE COUNTRY CLUB
MT TOM RANGE
N
COMMUNITY OF OF MOUNT TOM
BOSTON MAINE R.R.
KENNEDY CREEK
91
RAIL YARD
EXISTING PONDS
5
HOLYOKE
EASTHAMPTON
CONNECTICUT RIVER
flow
PLANT AREA
OIL STORAGE
MT HOLYOKE RANGE
NOTE: PLANT CONFIGURATION SHOWN IS PRIOR TO COAL CONVERSION
1000
500
0
1000
FEET
THERMOPYLAE

Figure 3-3. Site Soils as Plotted by USDA (1978).


Legend
W-WATER
SOIL BOUNDARY
FaB-BURIED FLY ASH SOIL
Wo-WINOOSKI SERIES
Te-TERRACE ESCARPMENTS
RHE-ROCK OUTCROP
Cp-COAL PILE SOIL
HbA-HbB-HADLEY SERIES
Fa-FLY ASH SOIL
Su-SUNCOOK SERIES
HaA?
HbB?
HbA
HbB
Su
Wo
FaB
RHE
Cp
Fa
W
SITE
To
N
CONNECTICUT RIVER

SOURCE: GIBBS & HILL, 1981.

Figure 3-4. Onsite Soils as Plotted by Gibbs & Hill (1981).

ash was deposited on the lower strata of Hadley-Winooski soils. An 8 to 12 inch layer of yellowish silt to sandy loam overlies the fly ash. The buried fly ash soils are deep, well drained and nearly level to sloping (0 to 6 percent) and well above normal stream level. Seasonal high water level within these soils is 4 to 8 feet above river level. Permeability rates are low (2.3×10^{-4} cm/sec.).

This soil is located to the southwest of the plant and west and south of the plant railroad yard and south of Kennedy Brook. The majority of the land area is completely grass covered with patchy primary successional natural regenerative tree growth, but in some areas, the soil cover has developed rill and gully erosion of the highly erodible fly ash.

2) Uncovered fly ash soils (Fa). This soil type is located to the southeast of the plant along the shore of the Connecticut River. The area is sparsely covered by grasses and secondary successional natural regenerative tree growth. The area is also the site of several active wastewater disposal ponds for the generating station.

This soil type apparently overlies a preexisting municipal solid waste disposal site, that extends to approximately 25 feet below present ground level. Fifteen feet of gray fine- to medium-sand-textured fly ash covers the old municipal waste.

Permeability of the fly ash soils is low (5.0×10^{-4} cm/sec.). The uncovered fly ash soils are deep and nearly level to sloping (0 to 6 percent) and are located on the lower floodplain sites. Seasonal high water table is somewhat above river level, but no mottling of soil material is noted.

3.2 WATER RESOURCES

3.2.1 Surface Water

3.2.1.1 Major Drainage Features

The major water courses affecting the site are the Connecticut River and Kennedy Brook. The Connecticut River, which forms the eastern boundary of the site, is the predominant hydrologic feature. The total drainage area is more than 11,000 square miles. From the site to the north, the drainage area is about 8,300 square miles extending upstream through New Hampshire and Vermont, and into Canada. At the Mt. Tom site the Connecticut River is in a transitional stage: the generating station is near the upstream limit of the effects of the pool that forms behind the Holyoke Dam, 5.5 miles downstream, resulting in a partial transition from river to reservoir. Kennedy Brook is a relatively small perennial stream with a drainage area of 2.14 square miles. Kennedy Brook crosses the site from west to east to discharge into the Connecticut River.

Flow records for the Connecticut River near the site are available from the U.S. Geological Survey (USGS) at Montague City, Massachusetts, and at Thompsonville, Connecticut. The Mt. Tom site, at river mile 92, is 27 miles downstream of Montague City and 24 miles upstream of Thompsonville. Table 3-1 summarizes the flow characteristics of the Connecticut River. Based on a semilogarithmic interpolation of USGS data relative to drainage area, flow values at the Mt. Tom generating station were estimated to range from 310 cfs to 250,000 cfs, with an average flow of 14,300 cfs.

March, April, and May are generally high flow months. The low flow season generally runs through July, August, and September, with an average flow of about 5,000 cfs. The 10-year, 7-day low flow for the Connecticut River at Mt. Tom is 1,860 cfs based on interpolation of USGS (1980) information for the low flows at the nearest gaging stations.

Flood information for the Connecticut River is contained in a report by the U.S. Department of Housing and Urban Development (HUD, 1979). The HUD report is a flood insurance study for the city of Holyoke that provides peak flows and flood elevations for various recurrence intervals. These are presented in Table 3-2, where the flood elevations are for the reach of the Connecticut River that borders the Mt. Tom site.

Major historical floods occurred in 1927, 1933, 1936, 1938, and 1955. The flood of 1936 is the largest of record and provided the maximum flows of record shown in Table 3-1. It was approximately equal to the 500-year flood shown in Table 3-2.

TABLE 3-1

CONNECTICUT RIVER FLOW CHARACTERISTICS

Station	USGS Number	Drainage Area sq mi	Length of Record (years)	Flow in cfs Average	Flow in cfs Maximum of Record	Flow in cfs Minimum of Record	Flow in cfs 10-Year 7-Day Low Flow
Montague City, MA	01170500	7865	74	13,770	236,000	215	1670
Mt. Tom Generating Generating Station[a]	--	8300	--	14,300	250,000	310	1860
Thompsonville, CT	01184000	9661	50	16,370	282,000	968	2210

---

[a] Flow values interpolated based on drainage area.

Source: USGS, 1979, Resources Data, Water Year 1978.

TABLE 3-2

FLOOD SUMMARY - CONNECTICUT RIVER

	Recurrence Interval 10-Year	Recurrence Interval 50-year	Recurrence Interval 100-year	Recurrence Interval 500-year
Peak Flow (cfs) at Holyoke-W. Springfield Boundary	112,000	158,000	180,000	242,000
Flood Elevation (ft) at Mt. Tom Site	115	119	121	126

TABLE 3-3

PROJECTED 100-YEAR FLOOD WATER ELEVATIONS

	Holyoke Country Club 1/2 Mile Downstream of Powerplant	Mt. Tom Powerplant	Holyoke Corp. Bdry. 6/10 Mile Upstream of Plant
Flood Level (Feet, NGVD)			
HUD Model	122.0	122.5	122.5
NUSCO Model 1 (Oil Burning Configuration)	121.6	121.7	122.2
NUSCO Model 2 (Plant with initial coal conversion modifications)	121.6	121.7	122.2
NUSCO Model 3 (Same as Model 2 plus use of additional acreage)	121.6	121.7	122.2

Source: NUSCO, 1981d.

The peak 100-year flow at the Mt. Tom generating station is 180,000 cfs. The corresponding flood elevation is about 121 feet along the southern portion of the site, and increases to over 122 feet at the northern boundary (Table 3-2; Figure 3-5). The utility estimates that 77 acres of the property is within the 100-year floodplain (NUSCO, 1981b); NUSCO (1981d) has conducted model studies using the HEC-2 model developed by the U.S. Army Corps of Engineers to determine potential flood elevations at the site under three conditions: the pre-reconversion plant configuration; conversion with only one fly ash basin (see Figure 1-2); and conversion utilizing additional acreage south of Kennedy Brook for ash disposal. These interpretations correlate with those by HUD, and the utility has concluded that there would be no measurable increase in flood levels as a result of any planned development. These model study results are shown on Table 3-3.

No flow records are available for Kennedy Brook. The 100-year flood for Kennedy Brook was estimated from data for small drainage basins discussed in the HUD report. A semilog plot of peak flows versus drainage area yields a 100-year peak flow of about 200 cfs for Kennedy Brook. This value is conservative; it does not take into account the reduction in flood peak that would probably occur due to the highway culverts and ponds upstream of the site.

Kennedy Brook flood elevations are governed by backwater effects from the Connecticut River if river stages are above Elevation 100. (The brook enters the river at about Elevation 100 and is at about 105 feet MSL at the culvert at U.S. 5.) If the elevation of the Connecticut is about 100 feet or less, the flow in Kennedy Brook can reasonably be assumed to be normal flow. Using Manning's equation, the 100-year peak of 200 cfs would create a flood elevation of 106 feet or less between the Connecticut River and Route 5, the western boundary of the site. This elevation is insignificant; it is well below the 10-year level of the Connecticut River and well within the Kennedy Brook channel.

If the 100-year peak flow of Kennedy Brook is assumed to coincide with the 100-year peak of the Connecticut River (an unlikely event), then the Kennedy Brook flow of 200 cfs must be imposed upon the Connecticut River elevation of 121 feet. A rough approximation of the flow conditions is to apply Manning's equation assuming that the bottom elevation of the channel of Kennedy Brook is 121 feet, with the natural slope of the channel, 0.5 percent. With Manning's "n" set equal to .025, a flow of 200 cfs has a flow depth of about 0.8 feet. Thus the 100-year flood elevation of Kennedy Brook, under worst case conditions, would be approximately 122 feet, only one foot higher than the Connecticut River.

3.2.1.2 Existing Water Quality

The water quality of the Connecticut River is affected both upstream and downstream of the Mt. Tom site by waste treatment and industrial plant discharges. The USGS maintains a water quality monitoring station (No. 0117200) on the Connecticut River at Holyoke, Massachusetts, approximately 5.5 miles downstream of the Mt. Tom site. Table 3-4 summarizes water quality data from 1975 through 1980 from this station.

As part of the hydrogeologic study conducted by Gibbs & Hill (1981) for the utility, water quality samples were taken from the Connecticut River and from Kennedy Brook, during September 1980. A summary of water quality data from these analyses is presented in Table 3-5. On that table, Stations 1 through 5 are in the Connecticut River (see Figure 3-2) and Stations 6 and 7 are on Kennedy Brook. The data indicate that leachate from the old fly ash pond may impact water quality in Kennedy Brook during periods of low flow such as occurred when the samples were taken (Gibbs & Hill, 1981). Other factors such as road runoff and infiltration of the stream flow into surrounding sediments rather than inflow from ground water during periods of low flow in the brook are also probably contributing factors.

Following HWP's submittal of the first monitoring report to DEQE (February 1982), questions were raised by both the Northampton Conservation Commission and a group of concerned citizens as to the impacts of heavy metals concentration in the river. In response to these concerns, the utility engaged a consultant to collect samples using ultra-clean techniques. The sampling locations are shown on Figure 3-6, and their results are presented on Table 3-6. A detailed report summarizing the findings was submitted to DEQE by the utility in April 1982 (NUSCO, 1982c). This study analyzed samples of Connecticut River waters and bottom samples, and concentrations of metals in bottom-dwelling organisms (oligocheates); samples from wells onsite were also analyzed.

State water quality regulations are set by the Massachusetts Division of Water Pollution Control (MDWPC). The MDWPC has divided the Connecticut River into 18 segments:

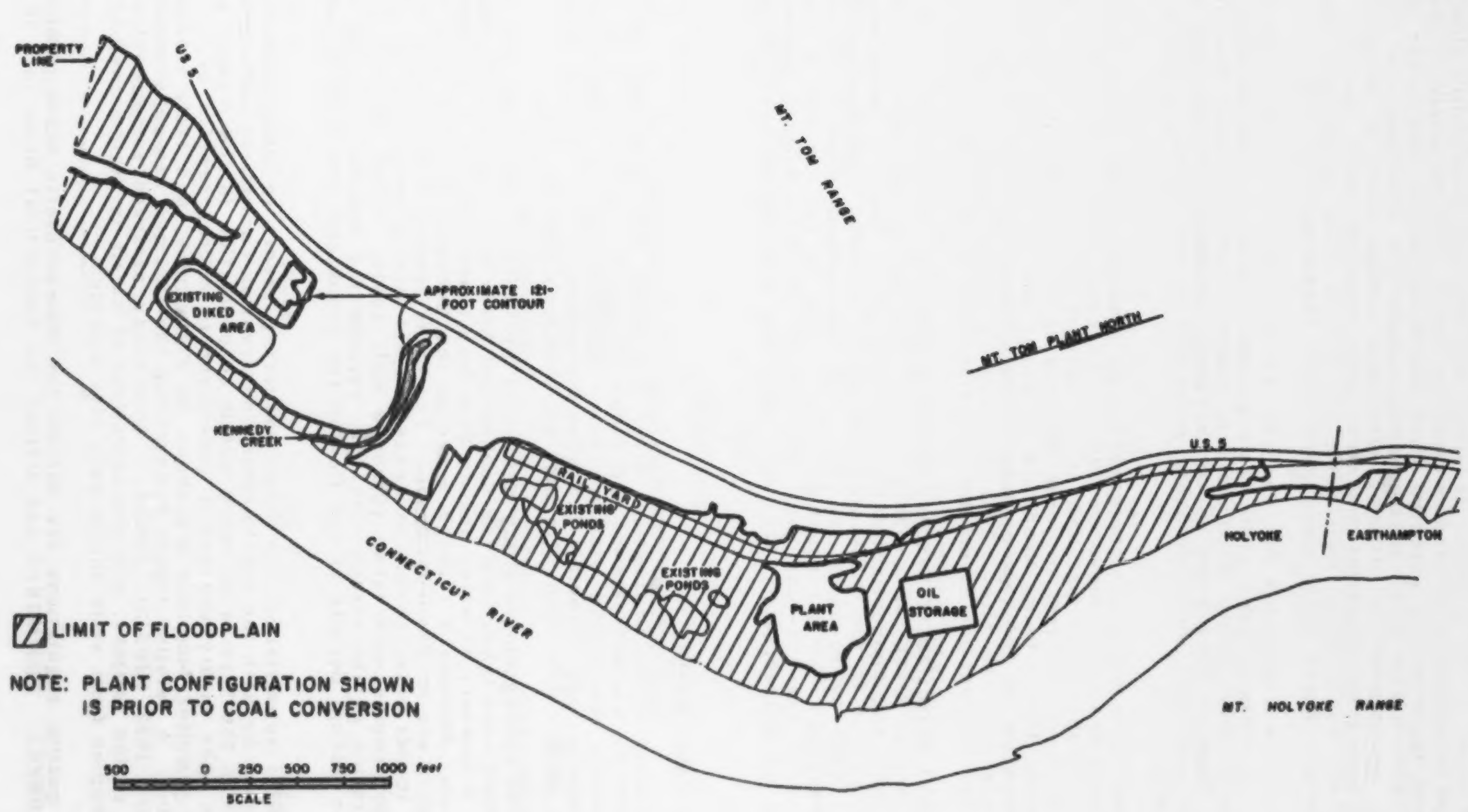

PROPERTY LINE
US 5
MT. TOM RANGE
EXISTING DIKED AREA
APPROXIMATE 121-FOOT CONTOUR
MT. TOM PLANT NORTH
KENNEDY CREEK
RAIL YARD
EXISTING PONDS
EXISTING PONDS
PLANT AREA
OIL STORAGE
U.S. 5
HOLYOKE
EASTHAMPTON
CONNECTICUT RIVER
MT. HOLYOKE RANGE
LIMIT OF FLOODPLAIN
NOTE: PLANT CONFIGURATION SHOWN IS PRIOR TO COAL CONVERSION
500 0 250 500 750 1000 feet
SCALE

Figure 3-5. Approximate Limit of 100-Year Floodplain.

TABLE 3-4

WATER QUALITY SUMMARY
CONNECTICUT RIVER AT HOLYOKE, MA

Page 1 of 2

PARAMETER	N	MEAN	STANDARD DEVIATION	MINIMUM VALUE	MAXIMUM VALUE
STREAMFLOW, INSTANTANEOUS (CFS)	55	4818.18181[1]	1899.42381	1500.00000	7000.0000
SPECIFIC CONDUCTANCE (MICROMHOS)	55	102.52727	22.32492	61.00000	176.0000
PH FIELD (UNITS)	55	6.89636	0.44895	5.90000	8.4000
TEMPERATURE, WATER (DEG C)	55	14.14182	8.79564	0.30000	26.0000
COLOR (PLATINUM COBALT UNITS)	0	.	.	.	.
TURBIDITY (NTU)	15	1.73000[2]	0.84384	0.50000	3.0000
OXYGEN, DISSOLVED (MG/L)	55	10.21455	2.00503	5.80000	14.5000
OXYGEN, DISSOLVED (PERCENT SATURATION)	18	92.44444	9.90081	71.99998	102.0000
OXYGEN DEMAND, CHEMICAL (LOW LEVEL) (MG/L)	37	14.13513	7.13817	0.00000	35.0000
OXYGEN DEMAND, CHEMICAL (HIGH LEVEL) (MG/L)	16	12.56250	10.04635	0.00000	36.0000
COLIFORM, TOTAL, IMMED. (COLS. PER 100 ML)	54	8244.93323[1]	12454.77714	46.99998	61999.8750
COLIFORM, FECAL, 0.45 UM-MF (COLS./100 ML)	48	802.26962[1]	1070.99259	69.99992	5799.9883
STREPTOCOCCI FECAL, KF AGAR (COLS. PER 100ML)	32	306.09337[1]	449.77972	14.00000	1799.9966
HARDNESS (MG/L AS CACO3)	1	0.00000	.	0.00000	0.0000
HARDNESS, NONCARBONATE (MG/L CACO3)	1	0.00000	.	0.00000	0.0000
CALCIUM TOTAL RECOVERABLE (MG/L AS CA)	15	10.57999	3.99556	2.70000	19.0000
CALCIUM DISSOLVED (MG/L AS CA)	0	.	.	.	.
MAGNESIUM, TOTAL RECOVERABLE (MG/L AS MG)	15	1.44667	0.45335	0.40000	2.0000
MAGNESIUM, DISSOLVED (MG/L AS MG)	0	.	.	.	.
SODIUM, DISSOLVED (MG/L AS NA)	0	.	.	.	.
SODIUM+ POTASSIUM DISSOLVED (MG/L AS NA)	0	.	.	.	.
POTASSIUM, DISSOLVED (MG/L AS K)	3	1.26667	0.40414	0.80000	1.5000
BICARBONATE (MG/L AS HCO3)	18	30.16667	7.96500	19.00000	44.0000
CARBONATE (MG/L AS CO3)	18	0.00000	0.00000	0.00000	0.0000
ALKALINITY (MG/L AS CACO3)	18	24.77778	6.44940	16.00000	36.0000
CARBON DIOXIDE DISSOLVED (MG/L AS CO2)	18	6.07778	6.96272	0.30000	32.0000
SULFATE DISSOLVED (MG/L AS SO4)	19	9.56316	2.46559	5.60000	17.0000
CHLORIDE, DISSOLVED (MG/L AS CL)	19	8.02632	2.33758	3.50000	12.0000
FLUORIDE, DISSOLVED (MG/L AS F)	0	.	.	.	.
SILICA, DISSOLVED (MG/L AS SIO2)	0	.	.	.	.
SOLIDS, RESIDUE AT 180 DEG. C DISSOLVED (MG/L)	0	.	.	.	.
SOLIDS, SUM OF CONSTITUENTS, DISSOLVED (MG/L)	0	.	.	.	.
SOLIDS, DISSOLVED (TONS PER AC-FT)	0	.	.	.	.
SOLIDS, DISSOLVED (TONS PER DAY)	0	.	.	.	.
SOLIDS, RESIDUE AT 105 DEG. C, SUSPENDED (MG/L)	55	11.81818	15.98969	0.00000	82.0000
SOLIDS, RESIDUE AT 105 DEG. C, TOTAL (MG/L)	55	75.09091	13.56230	38.00000	108.0000
SOLIDS, VOLATILE IN BOTTOM MATERIAL (MG/KG)	21	17089.90476[3]	14995.47026	0.00000	55000.0000
NITROGEN, NITRATE TOTAL (MG/L AS N)	54	0.26426[2]	0.09356	0.05000	0.5600
NITROGEN, NITRITE TOTAL (MG/L AS N)	54	0.00870[2]	0.00584	0.00000	0.0300
NITROGEN, NITRITE TOT IN BOT MAT (MG/KG	0	.	.	.	.
NITROGEN, NO2+NO3 DISSOLVED (MG/L AS N)	0	.	.	.	.
NITROGEN, AMMONIA TOTAL (MG/L AS N)	54	0.07426	0.06301	0.00000	0.3400
NITROGEN, AMMONIA TOTAL (MG/L AS NH4)	14	0.06214	0.05536	0.01000	0.1800
NITROGEN,AMMONIA + ORGANIC ONE DET TOT (MG/L AS N)	0	.	.	.	.
NITROGEN,AMMONIA + ORGANIC DIS. (MG/L AS N)	0	.	.	.	.
NITROGEN, ORGANIC TOTAL (MG/L AS N)	54	0.31574	0.24404	0.04000	1.3000
NITROGEN,AMMONIA + ORGANIC DIS. (MG/L AS N)	0	.	.	.	.
NITROGEN,NH4 + ORG. TOT IN BOT MAT (MG/KG AS N)	0	.	.	.	.
NITROGEN, TOTAL (MG/L AS NO3)	54	2.93519	1.19845	1.20000	8.6000
PHOSPHORUS, TOTAL (MG/L AS P)	54	0.04185[2]	0.02966	0.01000	0.1800
PHOSPHORUS, TOTAL (MG/L AS PO4)	14	0.10786[2]	0.04949	0.03000	0.4300
PHOSPHORUS, DISSOLVED (MG/L AS P)	0	.	.	.	.
ARSENIC TOTAL (UG/L AS AS)	7	0.42857[2]	0.53452	0.00000	1.0000
ARSENIC DISSOLVED (UG/L AS AS)	0	.	.	.	.

TABLE 3-4 (Continued)

Page 2 of 2

PARAMETER	N	MEAN	STANDARD DEVIATION	MINIMUM VALUE	MAXIMUM VALUE
BARIUM, TOTAL RECOVERABLE (UG/L AS BA)	7	24.71429[2]	24.95806	6.00000	80.0000
BARIUM, SUSPENDED RECOVERABLE (UG/L AS BA)	0	.	.	.	.
BARIUM, DISSOLVED (UG/L AS BA)	0	.	.	.	.
BORON, RECOV. FM BOTTOM MATERIAL (UG/G AS B)	7	106.28571	171.92994	1.00000	400.0000
CADMIUM SUSPENDED RECOVERABLE (UG/L AS CD)	0	.	.	.	.
CADMIUM DISSOLVED (UG/L AS CD)	0	.	.	.	.
CHROMIUM, TOTAL RECOVERABLE (UG/L AS CR)	14	12.00000	16.40201	1.00000	66.0000
CHROMIUM, SUSPENDED RECOV. (UG/L AS CR)	0	.	.	.	.
CHROMIUM, DISSOLVED (UG/L AS CR)	0	.	.	.	.
COBALT, TOTAL RECOVERABLE (UG/L AS CO)	12	1.10833	1.66103	0.00000	5.0000
COBALT, SUSPENDED RECOVERABLE (UG/L AS CO)	0	.	.	.	.
COBALT, DISSOLVED (UG/L AS CO)	0	.	.	.	.
COPPER, TOTAL RECOVERABLE (UG/L AS CU)	14	4.42857[2]	3.95580	2.00000	17.0000
COPPER, SUSPENDED RECOVERABLE (UG/L AS CU)	0	.	.	.	.
COPPER, DISSOLVED (UG/L AS CU)	0	.	.	.	.
IRON, TOTAL RECOVERABLE (UG/L AS FE)	14	610.00000	626.78668	130.00000	2100.0000
IRON, SUSPENDED RECOVERABLE (UG/L AS FE)	0	.	.	.	.
IRON, DISSOLVED (UG/L AS FE)	0	.	.	.	.
LEAD, TOTAL RECOVERABLE (UG/L AS PB)	14	12.00000	19.48990	0.00000	75.0000
LEAD, SUSPENDED RECOVERABLE (UG/L AS PB)	0	.	.	.	.
LEAD, DISSOLVED (UG/L AS PB)	0	.	.	.	.
MANGANESE, TOTAL RECOVERABLE (UG/L AS MN	14	68.78571	79.04505	20.00000	330.0000
MANGANESE, SUSPENDED RECOV. (UG/L AS MN)	0	.	.	.	.
MANGANESE, DISSOLVED (UG/L AS MN)	0	.	.	.	.
MERCURY TOTAL RECOVERABLE (UG/L AS HG)	7	0.38571	0.19518	0.10000	0.5000
MERCURY SUSPENDED RECOVERABLE (UG/L AS HG)	0	.	.	.	.
MERCURY DISSOLVED (UG/L AS HG)	0	.	.	.	.
SELENIUM, TOTAL (UG/L AS SE)	7	0.00000[1]	0.00000	0.00000	0.0000
SELENIUM, SUSPENDED TOTAL (UG/L AS SE)	0	.	.	.	.
SELENIUM, DISSOLVED (UG/L AS SE)	0	.	.	.	.
SILVER, TOTAL RECOVERABLE (UG/L AS AG)	7	0.57143[3]	1.13389	0.00000	3.0000
SILVER, SUSPENDED RECOVERABLE (UG/L AS AG)	0	.	.	.	.
SILVER, DISSOLVED (UG/L AS AG)	0	.	.	.	.
ZINC, TOTAL RECOVERABLE (UG/L AS ZN)	14	14.07143[1]	6.47438	7.00000	30.0000
ZINC, SUSPENDED RECOVERABLE (UG/L AS ZN)	0	.	.	.	.
ZINC, DISSOLVED (UG/L AS ZN)	0	.	.	.	.
GROSS ALPHA, DISSOLVED (UG/L AS U-NAT)	24	0.97917	0.86777	0.40000	4.5000
GROSS ALPHA, SUSP. TOTAL (UG/L AS U-NAT)	21	1.31905	1.91197	0.40000	7.3000
GROSS BETA, DISSOLVED (PCI/L AS CS-137)	24	2.39583	0.55127	1.10000	3.5000
GROSS BETA, SUSP. TOTAL (PCI/L AS CS-137)	21	1.23810	1.43544	0.40000	5.6000
GROSS BETA, DISSOLVED (PCI/L AS SR/YT-90)	24	1.98333	0.38749	1.10000	2.8000
GROSS BETA, SUSP. TOTAL (PCI/L AS SR/YT-90)	21	1.09524	1.26944	0.40000	5.2000
CARBON, ORGANIC TOTAL (MG/L AS C)	0	.	.	.	.
CARBON, ORGANIC DISSOLVED (MG/L AS C)	0	.	.	.	.
CARBON, ORGANIC SUSPENDED (MG/L AS C)	0	.	.	.	.
PHENOLS (UG/L)	18	0.33333	0.68599	0.00000	2.0000

TABLE 3-5

WATER QUALITY SUMMARY CONNECTICUT RIVER AND KENNEDY BROOK

Parameters[a]	Station No. 1	2	3	4	5	6	7	Low	High
Aluminum	≤0.1	≤0.1	≤0.1	0.15	<0.1	<0.1	<0.1	<0.1	0.15
Antimony	<0.1	≤0.1	≤0.1	≤0.1	≤0.1	<0.1	<0.1	<0.1	≤0.1
Arsenic	0.0025	<.002	<.002	.0025	.0045	<.002	<.002	0.002	0.0045
Barium	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	≤0.1	<0.1	≤0.1
Beryllium	<.005	<.005	≤.005	≤.005	<.005	<.005	<.005	<.005	≤.005
Boron	0.95	1.7	1.75	0.8	1.25	<0.5	<0.5	<0.5	1.75
Cadmium	.0013	.0013	.0017	.0025	.0012	<.0010	<.0010	<.0010	0.0025
Calcium	9.4	10.2	10.1	9.4	9.2	17.5	14.0	9.2	17.5
Chromium	≤.02	≤.02	<.02	0.06	0.03	<.02	<.02	<.02	0.06
Cobalt	<.05	<.05	<.05	<.05	<.05	<.05	<.05	<.05	<.05
Copper	≤.01	0.02	.025	0.03	0.02	0.01	0.015	≤.01	0.03
Iron	0.15	0.205	0.31	0.22	0.28	1.22	0.39	0.15	1.22
Lead	<.025	<.025	<.025	≤.025	<.025	<.025	<.025	<.025	≤.025
Magnesium	1.69	1.81	1.69	1.75	1.76	4.31	3.91	1.69	4.31
Manganese	0.04	0.05	0.07	0.05	0.05	0.18	0.22	0.04	0.18
Mercury	<.0002	<.0002	<.0002	0.00025	0.00035	0.003	<.0002	<.0002	.00035
Molybdenum	<.01	<.01	<.01	<.01	<.01	<.01	<.01	<.01	<.01
Nickel	0.03	0.02	0.02	0.03	0.025	0.055	0.05	0.02	0.055
Selenium	<.002	<.002	<.002	<.002	<.002	<.002	<.002	<.002	<.002
Silver	<0.1	≤0.1	0.15	<0.1	<0.1	0.2	0.15	<0.1	0.2
Strontium	≤.01	≤.01	≤.01	≤.01	<0.1	≤.01	<.01	<.01	≤.01
Sodium	7.25	6.5	6.9	7.05	7.1	20.20	15.3	6.5	20.20
Vanadium	<0.2	<0.2	<0.2	<0.2	<0.2	<0.2	<0.2	<0.2	<0.2
Zinc	0.03	0.07	0.03	0.04	0.04	0.05	0.01	0.01	0.07

Parameters	Units	Station No. 1	2	3	4	5	6	7	Low	High
Alkalinity	mg/l $CaCO_3$	32	32	32	32	32	56	42	32	56
Chlorides	mg/l	12	12	12	12	12	44	36	12	44
Color	Units	7	10	12	5	6	5	5	5	12
Fluorides	mg/l	.175	.155	.165	.18	.16	.59	.33	.155	.59
Nitrates	mg/lN	0.215	0.225	0.235	.205	0.22	.21	.16	.16	.235
pH	Units	7.4	7.4	7.4	7.45	7.6	7.6	7.3	7.3	7.6
Phosphates	mg/lP	0.037	0.045	<.025	<.025	.027	<.025	<.025	<.025	0.095
Specific Conductance	umhos/cm	119.5	119	115	114.5	113	259	195	113	259
Sulfates	mg/l	9.3	9.25	9.5	9.3	9.8	10.4	10.7	9.25	10.7
Sulfites	mg/l	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dissolved Oxygen	mg/l	8.05	8.09	8.26	8.33	8.52	7.42	8.61	7.42	8.61
Dissolved Solids	mg/l	78	84	74	69	70	148	128	69	148
Suspended Solids	mg/l	8.0	<1.0	<1.0	35	<1.0	12	2.5	<1.0	8.0
Water Temp	°C	19.0	17.9	20.5	22.3	22.4	14.0	15.0	14.0	22.5

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[a] Average concentrations in mg/liter. Stations 1 through 5, Connecticut River, Stations 6 and 7, Kennedy Brook (see Figure 3-2).

Source: Gibbs & Hill, 1981.

TABLE 3-6

METALS IN CONNECTICUT RIVER WATER SAMPLES
(in g/L, or ppb)

WESTERN SHORE SAMPLE	EASTERN SHORE SAMPLE	Cd (±.03)	Cr (±.05)	Cu (±0.3)	Fe (±40)	Mn (±1.0)	Ni (±0.6)	Pb (±.06)	Zn (±0.3)
16		<0.03	<0.05	1.51	186.2	13.24	0.63	0.14	2.8
1		0.07	0.11	2.22	263.2	15.90	1.24	0.20	21.3
15		0.03	<0.05	1.63	230.7	13.24	0.72	0.18	3.3
2		0.03	<0.05	1.76	276.6	13.41	0.68	0.18	4.9
3		0.03	<0.05	1.82	234.1	14.40	0.59	0.11	3.3
	14	<0.03	0.07	2.72	157.6	14.23	0.68	0.14	3.5
4		0.03	0.50	2.16	294.0	14.07	1.24	0.12	7.9
5		<0.03	0.25	1.94	641.6	19.06	0.55	0.37	3.3
6		0.03	0.15	2.07	257.6	27.21	0.63	0.18	3.1
7		<0.03	0.24	2.03	320.2	15.90	0.98	0.21	3.1
	13	<0.03	0.21	1.54	195.8	13.41	0.68	0.28	3.6
8		0.06	0.14	2.25	64.4	18.72	0.55	0.28	3.8
9		<0.03	0.18	2.22	183.5	15.90	0.81	0.28	3.3
10		<0.03	0.10	3.00	242.5	12.74	1.50	0.14	3.7
11		0.03	<0.05	1.32	328.1	15.90	0.89	0.18	3.0
12		0.03	0.11	1.98	322.5	11.07	1.02	0.25	3.1

Source: NUSCO, 1982.

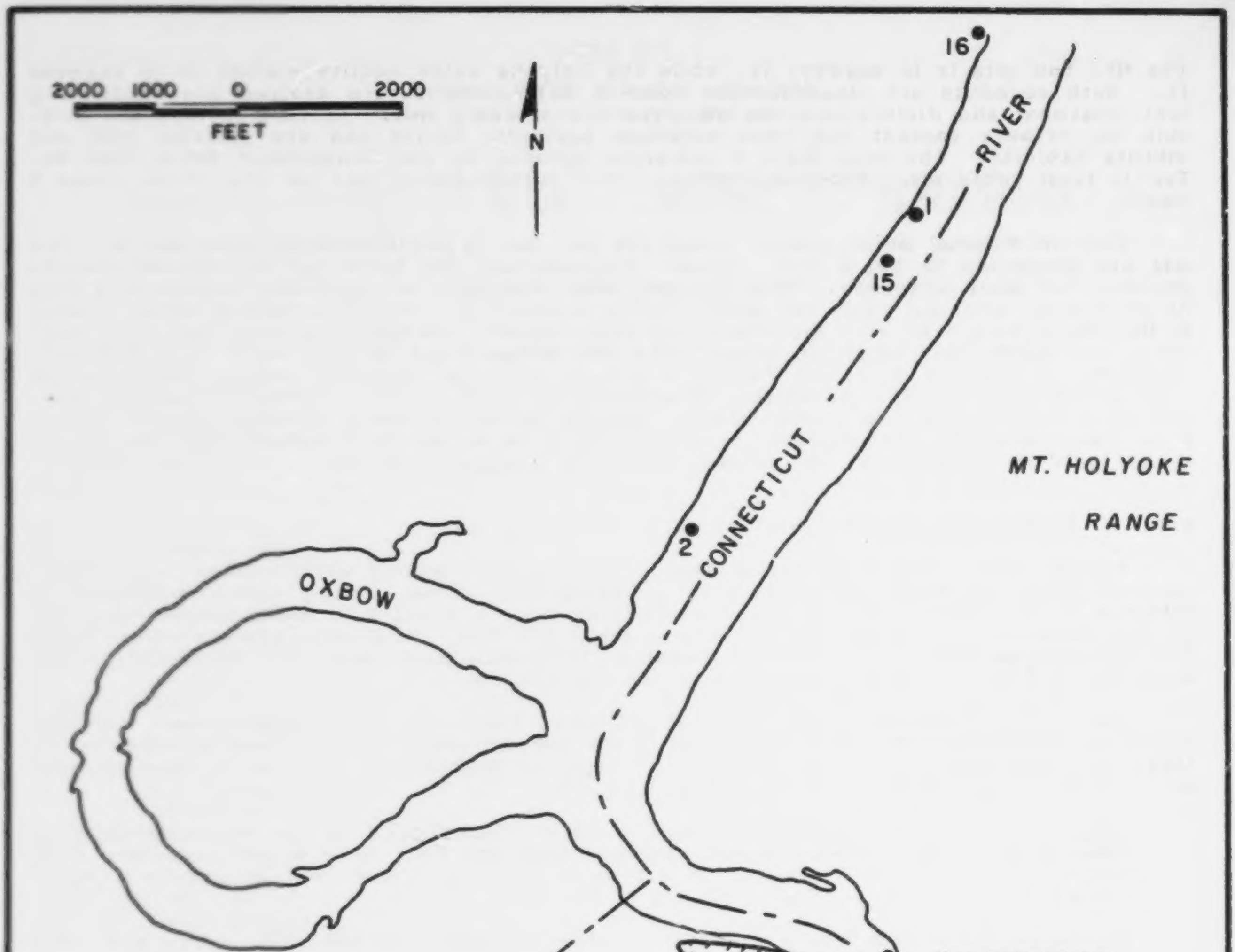
2000 1000 0 2000
FEET
N
16
RIVER
1
15
CONNECTICUT
MT. HOLYOKE
RANGE
2
OXBOW
THERMOPYLAE
3
14
4
5
13
6
7
8
9
STA.
GENERATING
MT. TOM
KENNEDY BROOK
10
11
12
HAMPSHIRE CO.
HAMPDEN CO.
MT. TOM RANGE

Figure 3-6. Sampling Study Sample Locations - Ultra-Clean.

The Mt. Tom site is in segment 10, while the Holyoke water quality station is in segment 11. Both segments are classified as Class B waters for future desired use, indicating that treatment and disinfection are required for drinking use. Class B waters are suitable for primary contact and have excellent aesthetic values and are suitable fish and wildlife habitats. The only Class B criterion violated by the Connecticut River near Mt. Tom is fecal coliforms. Dissolved oxygen (DO), temperature, and pH are within Class B limits.

Current Federal water quality standards for the Connecticut River near the Mt. Tom site are presented in Table 3-7. These standards are set forth by the EPA to provide guidance for state programs. They are not rules and have no regulatory impact, but they do provide a numerical basis for water quality evaluations. A comparison of water quality at Holyoke (Table 3-4) with the EPA fresh water aquatic standards reveals that lead, mercury, and silver concentrations exceed both the maximum and 24-hour limits. In addition, alkalinity is slightly over the desired average, and the maximum copper concentration reported exceeds the EPA maximum. Exceedance of these aquatic standards does not constitute a direct hazard to public health, because public drinking water is treated before it is distributed for consumption. Concentrations in excess of standards are not necessarily toxic to aquatic life, but rather, are above suggested maxima.

3.2.1.3 Plant Water Uses

The Mt. Tom generating station uses a once-through cooling water system. Its design capacity is 133.2 MGD (206 cfs). Very nearly all of the cooling water withdrawn is returned to the river. Normal plant wastewater flow is about 0.11 MGD; sluice water for fly ash requires 0.875 MGD, and for bottom ash 0.375 MGD. Additionally, once a year there is a maintenance wash and a chemical cleaning; the maintenance wash uses 6,000,000 gallons of water, and the chemical cleaning uses 560,000 gallons.

The utility received a new National Pollutant Discharge Elimination System (NPDES) Permit No. MA0005339 from EPA Region I and the Massachusetts DEQE (effective December 1, 1981) (see Appendix C). This permit authorizes 10 discharges, and establishes effluent requirements summarized in the following discussion.

Discharge 001 is the condenser cooling water discharge. It has an allowable flow rate of 133.2 MGD with a total residual chlorine limit of 0.1 milligram per liter (mg/liter). Also, pH is limited to 0.5 units deviation from the natural river water value.

Discharge 002 is from the wastewater treatment system; its allowable flow is 0.11 MGD with the following effluent limitations:

	Daily Average (mg/liter)	Daily Maximum (mg/liter)
Suspended Solids	30.0	100.0
Total Copper	1.0	1.0
Total Iron	1.0	1.0
Total Nickel	1.0	2.0
Total Zinc	1.0	2.0
Oil and Grease		15.0
pH	Between 6.0 and 9.0 units	

Discharge 004 is from the yard drains. Its maximum flow (from rainstorms) is estimated to be 0.029 MGD with the same oil and grease limitations as 002.

Discharge 005 is the traveling screen wash; its daily maximum flow is 0.374 MGD.

Discharge 006 is the reflecting pond overflow; no pollutants may be added to this discharge.

Discharge 007 is the oil trap overflow and highway runoff. The daily maximum flow for 007 is 0.010 MGD, with suspended solids and oil and grease limitations equal to

TABLE 3-7

FEDERAL WATER QUALITY STANDARDS
(As applied to the Mt. Tom site)

Parameter	Human Health	Fresh Water Aquatic Life Maximum	Fresh Water Aquatic Life 24-Hour Average
Alkalinity (as $CaCO_3$)	--	--	20 mg/liter[a]
Ammonia (as NH_3)	--	--	0.02 mg/liter[a]
Arsenic (total recoverable)	22 ng/liter[b,c]	440 µg/liter[b]	40 µg/liter[b]
Barium	1 mg/liter a	--	--
Beryllium	37 ng/liter[b,c]	130 g/liter[b]	5.3 µg/liter[b]
Boron	--	--	--
Cadmium (total recoverable)	10 µg/liter[b]	0.97 µg/liter[b,e]	0.008 µg/liter[b,e]
Chlorine (total residual)	--	--	2.0 µg/liter- salmonid fish[a] 10.0 µg/liter -other
Chromium (total recoverable, trivalent)[f]	170 µg/liter[b]	1500 µg/liter[b,e]	44 µg/liter[b]
Chromium (total recoverable, hexavalent)	50 mg/liter[b]	21 µg/liter[b]	0.29 µg/liter[b]
Fecal Coliform Bacteria	200 per 100 milliliter[a,g]	--	14 MPN per 100 milliliter[a,d]
Copper (total recoverable)	1 mg/liter[b]	8.0 µg/liter[b,e]	5.6 µg/liter[b]
Cyanide (as CN)	200 µg/liter[b]	52 µg/liter[b]	3.5 mg/liter[b]
Iron	0.3 mg/liter[a]	--	1.0 mg/liter[a]
Lead (total recoverable)	50 µg/liter[b]	46 µg/liter[b,e]	0.30 µg/liter[b,e]
Manganese	50 g/liter[a]	--	--
Mercury (total recoverable)	144 ng/liter[b]	0.0017 µg/liter[b]	0.00057 µg/liter[b]
Nickel (total recoverable)	13.4 µg/liter[b]	810 µg/liter[b,e]	42 µg/liter[b,e]
Nitrates, Nitrites	10 mg/liter[a]	--	--
Dissolved Oxygen	--	--	5.0 mg/liter
pH	5-9[a]	--	6.5-9.0[a]
Phenol	3.5 mg/liter[b,i]	10,200 µg/liter[b]	2,560 µg/liter[b]
Phosphorus (elemental)	--	--	--
Selenium (total recoverable)	10 µg/liter[b]	260 µg/liter[b]	35 µg/liter[b]
Silver (total recoverable)	50 µg/liter[b]	0.63 µg/liter[b,e]	0.12 µg/liter[b]
Solids (dissolved) and Salinity	250 mg/liter[a,j]	--	--
Sulfide-Hydrogen Sulfide	--	--	2 µg/liter[a]
Zinc (total recoverable)	5 mg/liter[b,i]	130 µg/liter[b,e]	47 µg/liter[b]

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[a] Source: EPA, 1976, Quality Criteria for Water, Washington, D.C. (The "Red Book").

[b] Source: EPA, 1980 "Water Quality Criteria Documents; Availability," Federal Register, Vol. 45, No. 231, November 28, 1980.

[c] Non-threshold carcinogen. Value presented represents incremental cancer risk increase of 1 in 100,000 cases over lifetime, if ingested.

[d] Shellfish waters only.

[e] Assuming hardness = 34 mg/l, the average value for Thompsonville, CT.

[f] Trivalent form is most commonly found in nature.

[g] Log-mean. Not more than 10 percent of total samples should exceed 400 per 100 ml.

[i] For taste and/or odor. Toxicity levels have not been established.

[j] Chlorides and sulfates.

those for discharge 002. In addition, any discharge from 007 must have a pH between 6.5 and 8.0 units.

Discharges 008 and 009 are from the bottom ash settling basin; the average monthly flow cannot exceed 0.25 MGD; other effluent limitations are the same as for 002.

Discharges 010 and 011 are from the fly ash basin; the average monthly flow must not exceed 1.0 MGD and other effluents must be the same as for 002.

3.2.2 Ground Water

The hydrogeologic setting at the Mt. Tom generating station consists of up to 200 feet of unconsolidated sediments of sands, silts, and gravels overlying older bedrock. Ground water generally moves through the unconsolidated sediments toward the Connecticut River more readily than through the bedrock, which acts as a lower barrier to the major portion of the flow.

A detailed hydrogeologic study conducted by Gibbs & Hill (1981) for NUSCO indicates that the 89-acre site may be divided into two distinct unconfined ground water systems - a northern aquifer and a southern aquifer, separated by an east-west trending bedrock ridge. (See Section A-A', Figure 3-1.) There is also another east-west trending ridge that bounds the northern limit of the site (Gibbs & Hill, 1981).

Ground water flow within the Quaternary sediments is somewhat restricted, due to these natural boundaries. The Triassic bedrock in the adjacent Mt. Tom Range acts as the western boundary, the northern bedrock ridge prevents shallow ground water from leaving the site to the north, the Triassic bedrock restricts flow in the vertical direction, and the Connecticut River acts as a constant head boundary (across which shallow ground water flow cannot travel) to the east. Finally, soils of low hydraulic conductivity in the southern portion of the site restrict ground water flow in that direction. These boundaries are important to any concept of the potential for contaminants to migrate from the Mt. Tom site.

Kennedy Brook may receive some discharge from shallow ground water at the site. The water table varies from an elevation of approximately 106 feet MSL at the southwestern boundary to somewhere around 100 feet MSL at the river during average flow conditions. The hydraulic gradient across the site averages 0.002 (Gibbs & Hill, 1981).

The Gibbs & Hill (1981) study was based on data collected from numerous soil borings, more than 20 wells, and information from a seismic survey. Currently, 28 wells exist at the site (see Figure 3-2). The following description of ground water conditions is based primarily on a review of that study and other published reports (see also Cederstrom and Hodges, 1967).

3.2.2.1 Aquifer Characteristics

Northern Aquifer

North of the bedrock ridge, the Quarternary deposits may be generally divided into three units:

1) an upper layer of fine-grained sand and interbedded silts which reaches an average depth (below surface) of 40 feet;

2) a middle unit, averaging 90 feet in thickness, consisting of medium- to coarse-grained sands and gravels with varying amounts of interbedded silts; and

3) a bottom sequence of fine-grained sands and silts of varying thickness.

The nature of the deposits is such that all three units do not occur in all wells. Fly ash deposits cover much of the area to depths of 10 feet.

Hydraulic conductivity values for the aquifers were determined from in situ falling and constant head tests, laboratory testing (permeameter and Burmister methods), and aquifer tests (Gibbs & Hill, 1981). Based on these data, the area north of the bedrock ridge can be considered as two hydrologic units: a surface layer (to 40 feet in depth) with a hydraulic conductivity value of 10^{-3} cm/sec.; and an underlying unit, the northern aquifer (which is considered to extend from 40 feet to bedrock), which was assigned a value of 10^{-2} cm/sec.

Southern Aquifer

Sediments in the upper 35 feet are similar to those in the northern section although somewhat finer grained throughout. The middle unit consists of 25 to 60 feet of fine-grained silty sands interbedded with some coarse sand and gravel lenses. The lower unit is composed of fine sand and silt, similar in texture to the upper unit. At the extreme southernmost extention of the property the upper layer is underlain by about 130 feet of interfingered silts and clays with occasional fine-grained sand lenses.

Permeability values diminish markedly in the southern area, where a range of 1 x 10^{-3} to 1 x 10^{-5} cm/sec. were calculated (Gibbs & Hill, 1981).

Bedrock Aquifer

Detailed hydrogeologic information on the bedrock aquifer is not currently available. In order to better understand the onsite hydraulic characteristics, Gibbs & Hill (1981) performed a series of pressure tests in the bedrock. Results of these tests show permeability ranges from 0.2 to 2.3 gpd/ft^2 beneath the northern aquifer down to nearly 0 gpd/ft^2 in the southern section.

Direction of Ground Water Flow

Ground water generally flows toward the Connecticut River. Water levels have been taken periodically in 25 of the wells at the site. Based on measurements made on October 13 and 14, 1981, shallow ground water flow in both the northern and southern aquifers parallels the east-west trending bedrock ridge. There is an indication that some flow from the southern aquifer discharges into Kennedy Brook and that there is probably an upward component to flow from water deeper in the aquifer. This is indicated by a 0.7-foot head difference in wells OW-12 and 13A, which are screened at different depths at approximately the same location. There was an unexplained ground water depression, as seen in wells OW-8, 7, and 4, in the northern aquifer in the area of the coal pile and its collection basin in October 1981 (see Figure 3-7).

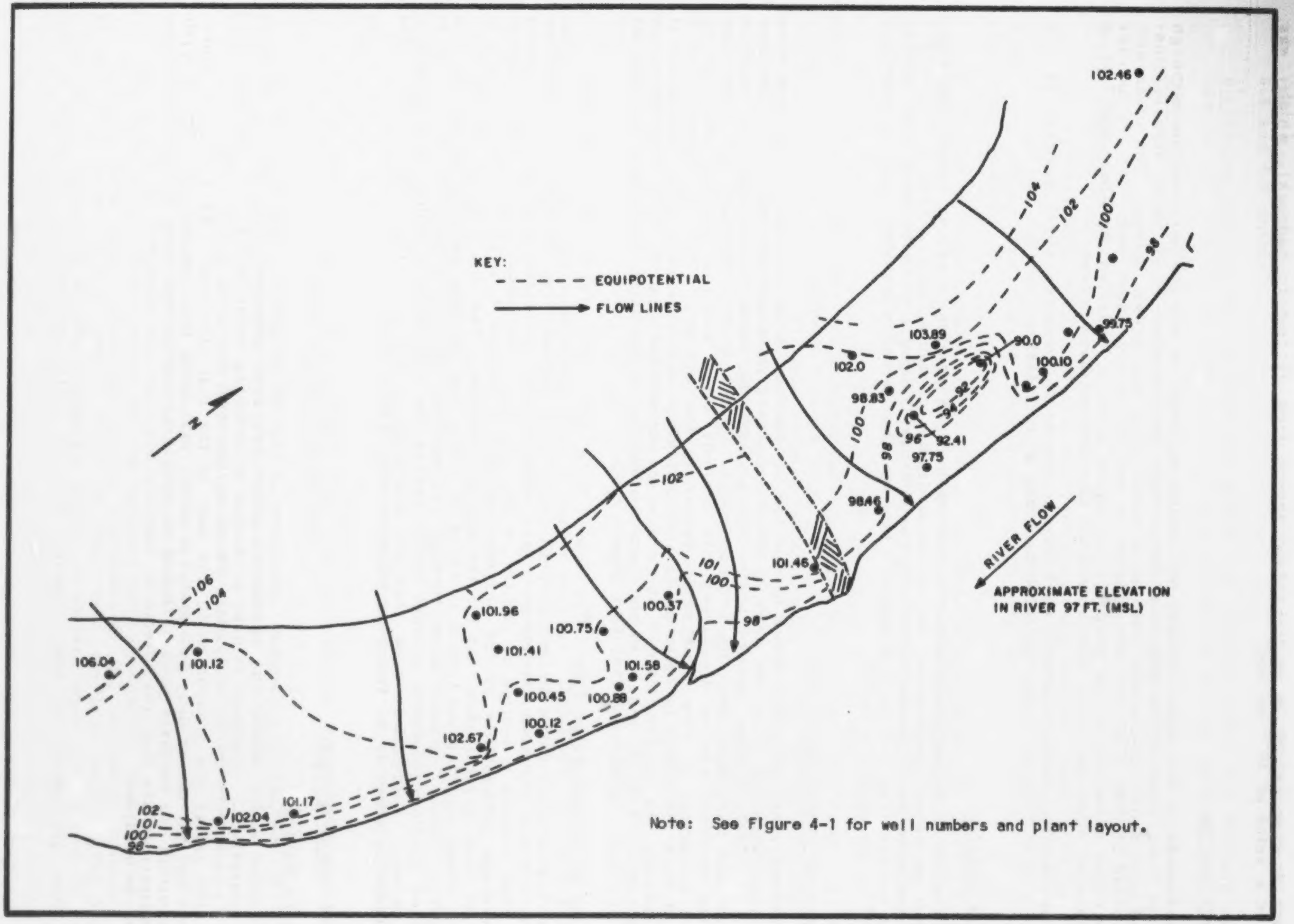
Quantity of Ground Water Flow

Owing to differences in sediment characteristics between the northern and southern aquifer systems, calculated discharges vary considerably. In order to estimate the ground water flow through a section of aquifer, a flow net was constructed (Gibbs & Hill, 1981). The average permeability of the northern aquifer is around 1 x 10^{-2} cm/sec. which is about 10 times greater than that for the southern system. The flow through the northern aquifer under existing conditions is about 62 cubic feet per day per foot of aquifer (cu ft/day/ft). Flow of ground water through the southern aquifer is markedly less owing to the finer grained sediments present which reduce the permeability values to around 1 x 10^{-3} cm/sec. Calculations show that the discharge to the river from the southern area is reduced to about 17 cu ft/day/ft (Gibbs & Hill, 1981).

3.2.2.2 Water Quality

Northern Aquifer

Ground water within the northern aquifer has been adversely affected by previous plant operations. Elevated values, in excess of drinking water levels, for sulfates (1560 mg/l), iron (24.73 mg/l), manganese (8.52 mg/l), total dissolved solids (2404 mg/l), and odor (100 units) are present north and east of the coal pile area. As a further consequence, the pH values drop to about 3.3 units, indicating that the ground water is quite acidic within the leachate plume. Based on both geophysical and water sampling analyses, the indications are that the effects of leachate migration are observed as deep as 85 feet within the section.


KEY:
EQUIPOTENTIAL
FLOW LINES
N
RIVER FLOW
APPROXIMATE ELEVATION IN RIVER 97 FT. (MSL)
102.46
104
102
100
98
99.75
100.10
90.0
103.89
102.0
98.83
92
94
96
92.41
97.75
98.46
101.46
101
100
98
102
100.37
100.75
101.96
101.41
101.58
100.88
100.45
100.12
102.67
106
104
106.04
101.12
101.17
102.04
102
101
100
98

Note: See Figure 4-1 for well numbers and plant layout.

Figure 3-7. Ground Water Contour Map (October 13, 1981).

Southern Aquifer

Ground water quality within the southern aquifer is markedly improved over that of the northern unit; however, a weak contamination plume exists, probably due to previous disposal of fly ash. Values for iron (89 mg/liter), sulfate (390 mg/liter), manganese (2.0 mg/liter), and odor (6 units) exceed drinking water standards. Iron concentrations of 10.1 mg/liter are found as deep as 100 feet below land surface.

3.2.2.3 Ground Water Use

Onsite Wells

Two wells onsite are used by the utility as back-up water sources.

Private Wells

There are two private wells within three-fourths mile of the site which tap the bedrock aquifer but their exact locations are not known. (The Mt. Tom Greenhouse well is to the south of the HWP property about 2,000 feet and the McKenney Electric Company well is about 3,800 feet to the north.)

Because the Mt. Tom Greenhouse and McKenney wells are believed to be located hydraulically upgradient of the Mt. Tom site, they are probably beyond the area of influence of leachate from the plant, and water quality changes related to coal conversion are not anticipated.

Public Supplies

Several communities in the vicinity receive all or part of their water supply from ground water. Easthampton uses ground water as a source of public water, but this city is upstream, on the north side of the Mt. Tom Range, and would not be affected by ground water conditions at the Mt. Tom generating station.

South Hadley, across the Connecticut River from the plant, provides water to residents of Water District No. 2 from the Dry Brook well. This supply probably is not connected hydraulically to the shallow aquifers at Mt. Tom because the river provides a constant head barrier to shallow flow across it. Tests over several years have indicated no change in the water quality at the South Hadley well relative to potential contamination from coal burning activities (Gibbs & Hill, 1981).

3.3 AIR RESOURCES

3.3.1 Climate and Meteorology

A National Weather Service station located at Bradley International Airport (Windsor Locks, CT) is approximately 25 miles south of the generating station at an elevation of 160 feet above sea level. Because of its proximity to the Mt. Tom generating station, this weather station provides data which approximate the climatology of the site.

The region's temperate climate changes seasonally from cold dry Canadian air to warm maritime air from the Gulf of Mexico, the Caribbean, or the Atlantic. The location of the polar front, a boundary between the cold, dry polar air and the warm moist tropical air, moves from just south of New England in the winter to just north of it in the summer. As a result, winter weather tends to be stormy and variable from day to day and summer weather tends to be warm and pleasant.

The average (mean) annual temperature is 49°F. January and February, the coldest months, have mean temperatures of about 17°F; the lowest recorded temperature is 26°F below zero (January 1961). July, the warmest month, has a mean temperature of 61°F; the highest recorded temperature is 102°F (July 1966). Relative humidity is highest during morning hours and lowest during afternoon hours.

Precipitation occurs mainly as thunderstorms in summer and as rain and snowfall in winter. The annual average precipitation is 43 inches, about a tenth of which is snow.

The mean annual wind speed is 9 miles per hour, and the average annual prevailing direction is from the south. Table 3-8 summarizes the climatological features of this region.

Surface wind data at the generating station are available for a 4-year period. Because evaluation of dispersion climatology requires more historical data, these data were supplemented with data collected at the Bradley International Airport in Windsor Locks, CT.

The annual wind rose for Windsor Locks (Figure 3-8) shows the predominant north-south wind directions in the Connecticut River Valley. The 4-year wind rose developed from the Mt. Tom meteorological tower data is shown for comparison in Figure 3-9. The two wind roses are seen to be basically very similar; the north-south predominance of the wind direction is slightly more pronounced at the Mt. Tom site because of the nearby Mt. Tom and Mt. Holyoke ridges.

Air pollutants emitted from a point source, such as a stack, are carried downwind and diluted by mixing in the atmosphere in a roughly cone-shaped plume. High wind speeds facilitate greater dilution, allowing the atmosphere to accept higher pollutant loads without exceeding safe or legal ground-level concentrations. If the air is stagnant, or the pollutants can only mix in a shallow layer, ambient levels of pollution will increase. If mixing heights are below 500 meters and wind speeds are less than 4 meters per second (about 9 mph) for at least 2 days, the potential exists for significant increases in ambient levels of pollution (Holzworth, 1972). These conditions were not observed in this region during the 5-year period from 1960 to 1964. Consequently, dispersion of pollutants around the Mt. Tom generating station is considered relatively good.

Temperature inversion, a condition in which atmospheric temperature increases with altitude, also tends to aid development of high ground-level pollution concentrations. The warm layer overlying a cooler one inhibits vertical mixing. While low-level nighttime inversions occur on 50 percent of winter days, 60 percent of spring days, and 70 percent of summer and fall days, these inversions are shortlived and do not indicate high air pollution potential (Hosler, 1961).

3.3.2 Ambient Air Quality

The Mt. Tom generating station lies within the Hartford-New Haven-Springfield Interstate Air Quality Control Region (AQCR 42). Measurements of ambient air quality in AQCR 42 were available from monitoring networks operated by the Massachusetts Department of Environmental Quality Engineering (DEQE), the Connecticut Department of Environmental Protection (CDEP), the Pioneer Valley Private Monitoring Group (PVPMG), and NUSCO. The monitoring data produced by NUSCO and the PVPMG are audited and checked for quality assurance by the DEQE. The ambient air quality data presented in this section were taken from the following sources:

- The National Aerometric Data Bank for AQCR 42, for the years 1977-1980, as supplied by EPA.
- A summary of air quality data in the lower Pioneer Valley for the years 1977, 1979, and 1980, supplied by the DEQE.
- Documents submitted by NUSCO to EPA Region I in support of the request for a Delayed Compliance Order (DCO) for the Mt. Tom generating station fuel conversion.

The locations, by city or town, of most AQCR 42 monitors for which data were available are shown in Figure 3-10. (Not shown are monitor locations for trace metals, nitrates, sulfates, and noncontinuous monitors for SO_2 and NO_2.) A summary of the highest pollutant concentrations, or of those concentrations most representative of the Mt. Tom location, is presented in Table 3-9. Data for SO_2 are not given in this table, but a detailed summary of all SO_2 data is presented in Table 3-10. The locations of SO_2 and PM monitors in the vicinity of the Mt. Tom generating station are shown in greater detail in Figure 3-11. A detailed summary of PM data for monitors in the Mt. Tom vicinity is given in Table 3-11.

The effects of the Mt. Tom station emissions prior to reconversion to coal are included in the ambient data presented in Tables 3-10 and 3-11. These data, therefore, represent background levels of pollution concentration for the purpose of assessing changes that may occur as a result of conversion to coal fired operation at the station.

TABLE 3-8

CLIMATOLOGICAL SUMMARY[a]

PRECIPITATION (inches)	
Normal Annual Total	43.37
Maximum 24 Hours (August 1955)	12.12
Mean number of days with thunderstorms	22
SNOWFALL (inches)	
Mean Annual Total	58.0
Monthly Maximum (March 1956)	43.3
TEMPERATURE (°F)	
Mean Annual	49.1
Record High (July 1966)	102
Record Low (January 1961)	-26
AVERAGE RELATIVE HUMIDITY (%)	
Hour	
1 AM	77
7 AM	78
1 PM	53
7 PM	63
WIND	
Prevailing Direction	South
Mean Speed (mph)	8.8

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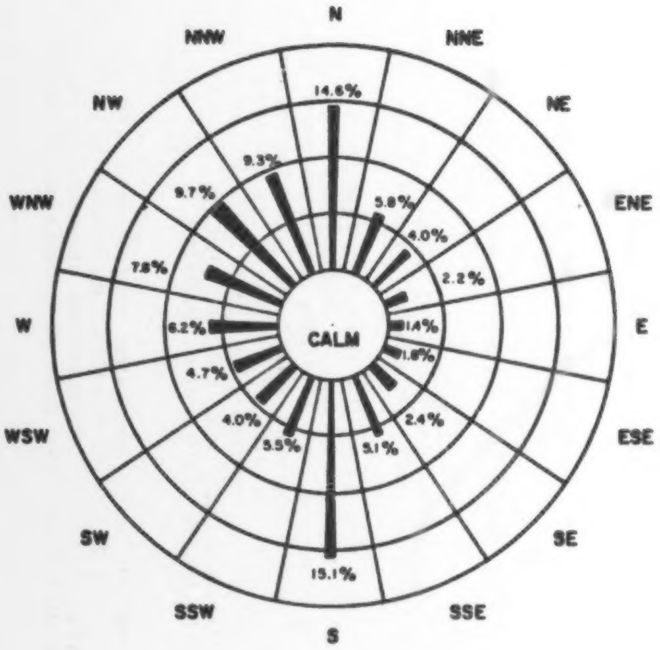
[a] Bradley International Airport, Windsor Locks, CT (1941-1970).

Source: U.S. Department of Commerce, National Climatic Center, 1979.



SOURCE: Radian Corporation, 1975.

Figure 3-8 Annual Wind Rose - Bradley International Airport, Windsor Locks, Ct. 1964 to 1973.

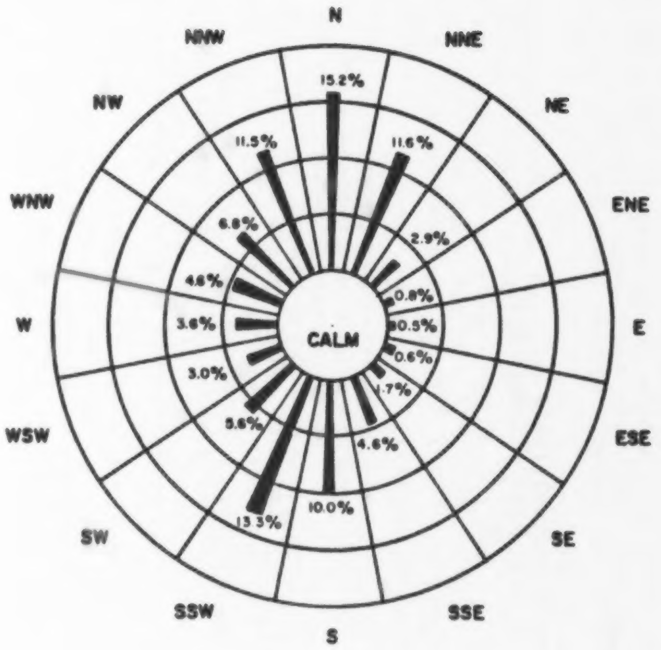
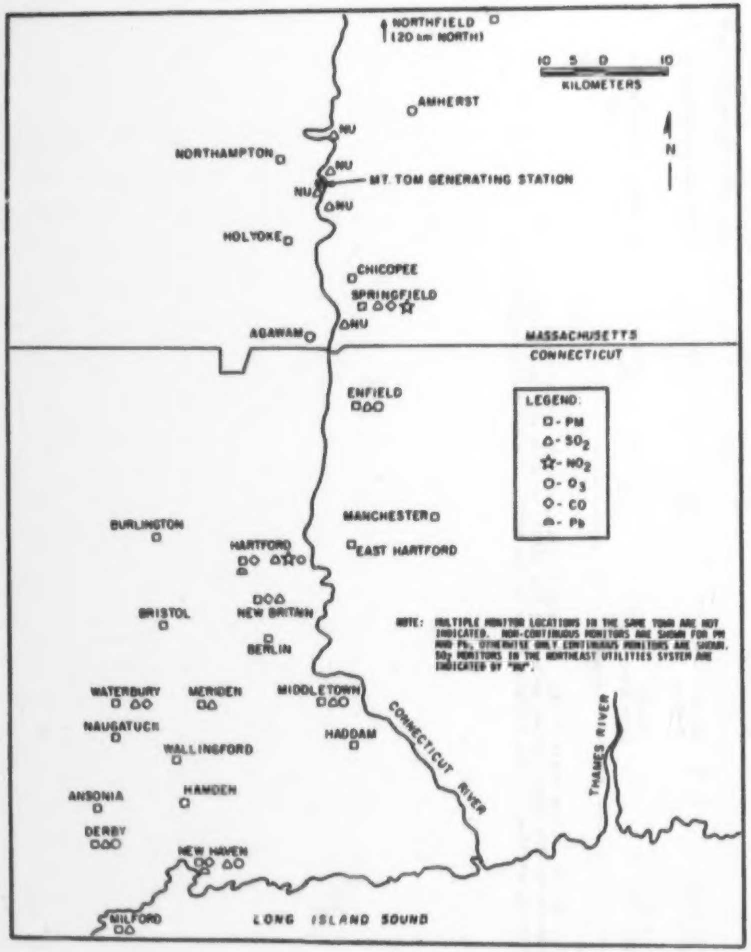
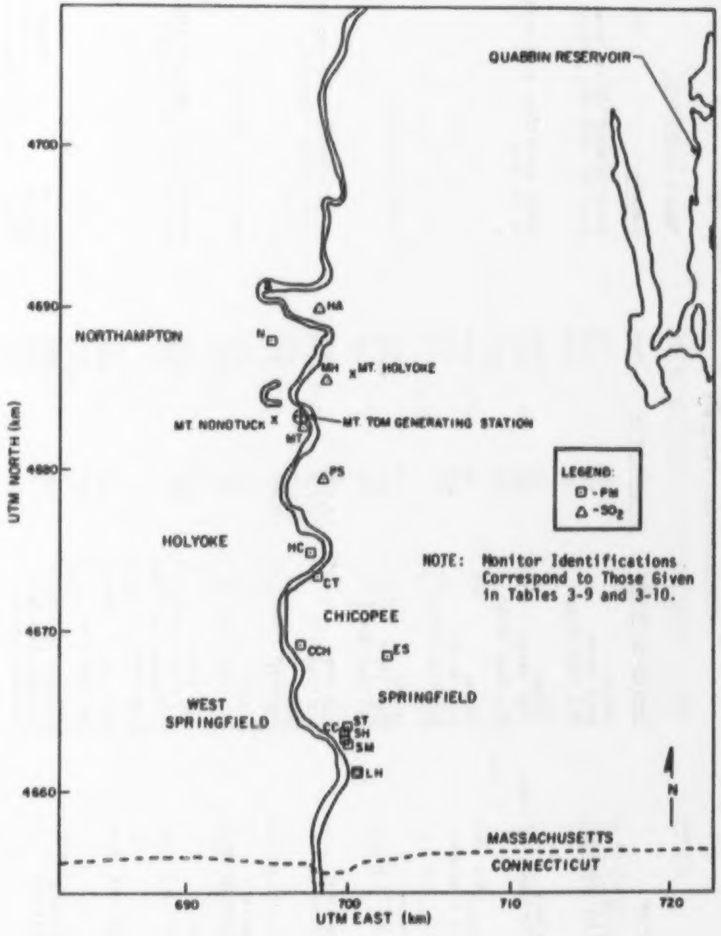


Figure 3-9. Annual Wind Rose - Mt. Tom Station Meteorological Tower, Mt. Holyoke, MA, April 1976 to December 1979,


NORTHFIELD (20 km NORTH)
10 5 0 10
KILOMETERS
AMHERST
N
NU
NORTHAMPTON
NU
MT. TOM GENERATING STATION
NU
NU
HOLYOKE
CHICOPEE
SPRINGFIELD
NU
AGAWAM
MASSACHUSETTS
CONNECTICUT
ENFIELD
LEGEND:
□ - PM
△ - SO_2
☆ - NO_2
○ - O_3
◇ - CO
⌓ - Pb
MANCHESTER
BURLINGTON
HARTFORD
EAST HARTFORD
NEW BRITAIN
BRISTOL
BERLIN
WATERBURY
MERIDEN
MIDDLETOWN
NAUGATUCK
WALLINGFORD
HADDAM
CONNECTICUT RIVER
THAMES RIVER
ANSONIA
HAMDEN
DERBY
NEW HAVEN
MILFORD
LONG ISLAND SOUND

NOTE: MULTIPLE MONITOR LOCATIONS IN THE SAME TOWN ARE NOT INDICATED. NON-CONTINUOUS MONITORS ARE SHOWN FOR PM AND Pb, OTHERWISE ONLY CONTINUOUS MONITORS ARE SHOWN. SO_2 MONITORS IN THE NORTHEAST UTILITIES SYSTEM ARE INDICATED BY "NU".

Figure 3-10. Air Quality Monitoring Stations in AQCR 42.


QUABBIN RESERVOIR
4700
4690
4680
4670
4660
UTM NORTH (km)
NORTHAMPTON
HA
N
MH
MT. HOLYOKE
MT. NONOTUCK
MT
MT. TOM GENERATING STATION
PS
LEGEND:
□ - PM
△ - SO_2
HOLYOKE
HC
CT
CHICOPEE
CCH
ES
WEST SPRINGFIELD
SPRINGFIELD
CC
ST
SH
SM
LH
N
MASSACHUSETTS
CONNECTICUT
690
700
710
720
UTM EAST (km)

NOTE: Monitor Identifications Correspond to Those Given in Tables 3-9 and 3-10.

Figure 3-11. Air Quality Monitors in the Local Area of the Mt. Tom Generating Station.

TABLE 3-9

SUMMARY OF CRITICAL AIR QUALITY MEASUREMENTS IN AQCR 42, 1977 THROUGH 1980[a]
(Concentrations in μ g/m^3)

Page 1 of 2

Pollutant	Location	Averaging Period	Concentration	Year	Remarks
PM	Chicopee (939 Chicopee St)	Annual	95	1978	Nonattainment in isolated areas Data for 1978 only, NAAQS violation
		High 24-hr	178	1978	
		2nd High 24-hr	162	1978	
	Waterbury (DOT entrance to I-84)	Annual	82	1977	NAAQS violation, also annual value of 80 in 1978
		High 24-hr	292	1977	
		2nd High 24-hr	255	1977	
	Waterbury (Waste Treatment Plant)	Annual	70	1977	
		High 24-hr	416	1978	
		2nd High 24-hr	170	1978	
	New Haven (677 State St)	Annual	79	1979	NAAQS Violation
		High 24-hr	251	1979	
		2nd High 24-hr	212	1978	
CO	Springfield (E. Columbus Ave)	High 8-hr	12,610	1977	Nonattainment in Springfield, MA and in CT NAAQS violation
		2nd High 8-hr	11,920	1977	
		High 1-hr	20,630	1977	
		2nd High 1-hr	19,480	1977	
NO_2	Springfield (E. Columbus Ave)	Annual	45	1977	Continuous Monitor
		2nd High 1-hr	175	1977	
O_3	Agawam	High 1-hr	363	1980	Nonattainment demonstrated at every monitor site in the AQCR
		2nd High 1-hr (different day than high 1-hr)	305	1980	
	Amherst	High 1-hr	285	1977	
		2nd High 1-hr	285	1977	
Pb	Springfield (25 Mill St)	Calendar Quarter	2.9	1978	4th Qtr NAAQS
		Calendar Quarter	1.7	1979	1st Qtr Violations
		Calendar Quarter	2.0	1979	4th Qtr (only 3 observations)
	New Haven (715 State St)	Calendar Quarter	1.8	1978	3rd Qtr
		Calendar Quarter	2.1	1978	4th Qtr NAAQS Violations
		Calendar Quarter	1.6	1979	4th Qtr
Sulfate	Chicopee (Gratten and Meadow Streets)	High 24-hr	217	1979	No NAAQS established, gravimetric method
		High 24-hr	24.9	1979	Colorimetric method, Site operated only 1st 3 months of 1979
	Springfield (25 Mill St)	Annual	8.7	1978	Colorimetric method
		High 24-hr	29.9	1979	
Nitrate	Springfield (25 Mill St)	Annual	3.1	1978	No NAAQS established
		High 24-hr	11.8	1980	

---

[a] Excepting data for SO_2, for which see Table 3-103. Concentrations presented are either the maximum values observed in the AQCR, values exceeding the NAAQS, or else are for stations near the Mt. Tom generating station, if the highest value in the AQCR could not be representative of the Mt. Tom site.

TABLE 3-9 (continued)

Pollutant	Location	Averaging Period	Concentration	Year	Remarks
Trace Metals					
	Springfield (25 Mill St.)				No NAAQS established. Monitor site operation began January 1978, data available through April 1980.
Beryllium		Annual High 24-hr	0.17 0.24	1979 1980	OSHA 8-hr limit 2.0[b]
Cadmium		Annual High 24-hr	0.002 0.009	1978, 1979 1978	OSHA 8-hr limit 200.0
Chromium		Annual High 24-hr	0.005 0.012	1979 1978	OSHA 8-hr limit 1,000.0
Cobalt		Annual High 24-hr	0.0032 0.0039	1979 1980	OSHA 8-hr limit 100.0
Copper		Annual High 24-hr	0.06 0.17	1978 1978	OSHA 8-hr limit 1,000.0
Iron		Annual High 24-hr	0.96 3.26	1978 1978	OSHA 8-hr limit 10,000.0[c]
Manganese		Annual High 24-hr	0.03 0.08	1978 1978	OSHA 8-hr limit 5,000.0
Nickel		Annual High 24-hr	0.0144 0.0651	1978 1980	OSHA 8-hr limit 1,000.0
Titanium		Annual High 24-hr	0.0244 0.1008	1978 1978	OSHA 8-hr limit 15,000.0[d]
Vanadium		Annual High 24-hr	0.054 0.436	1979 1980	OSHA 8-hr limit 500.0[e]

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[b] The OSHA (Occupational Safety and Health Administration) limits are not ambient standards, but apply only to work places where the indicated contaminant is thought to be a potential occupational hazard. They are presented only for comparison to the observed ambient maxima in this context (U.S. Department of Labor, 1976).

[b] Applies to "iron oxide fume."

[d] Applies to titanium dioxide.

[e] Applies to V_2O_5 dust.

TABLE 3-10

YEARLY SUMMARY OF AVAILABLE SULFUR DIOXIDE AMBIENT AIR QUALITY DATA IN THE AQCR 42[a]

(Concentrations in $\mu g/m^3$)

Location	Averaging Period	1977	1978	1979	1980
Hopkins Academy[b] (HA)	Annual	38	32	29	29
	Highest 24-hr	131	149	144	136
	2nd Highest 24-hr	131	148	144	132
	Highest 3-hr	229	225	232	283
	2nd Highest 3-hr	222	214	208	237
Mt. Holyoke[b] (MH)	Annual	--	33	30	34
	Highest 24-hr	--	174	131	172
	2nd Highest 24-hr	--	173	131	172
	Highest 3-hr	--	227	200	304
	2nd Highest 3-hr	--	222	194	286
Mt. Tom[b] (MT)	Annual	32	27	27	27
	Highest 24-hr	147	140	113	79
	2nd Highest 24-hr	134	139	113	79
	Highest 3-hr	252	298	221	204
	2nd Highest 3-hr	222	276	214	177
Pine St. (PS)	Annual	37	33	30	31
	Highest 24-hr	153	259	143	105
	2nd Highest 24-hr	151	258	142	104
	Highest 3-hr	267	457	241	331
	2nd Highest 3-hr	263	404	219	312
Long Hill (LH)	Annual	43	49	50	50
	Highest 24-hr	230	241	294	271
	2nd Highest 24-hr	229	240	293	270
	Highest 3-hr	384	440	543	510
	2nd Highest 3-hr	379	440	521	505
Milford	Annual	26	30	27	36
	Highest 24-hr	134	141	162	173
	2nd Highest 24-hr	104	123	157	167
	Highest 3-hr	249	245	308	383
	2nd Highest 3-hr	238	197	200	362
Meriden	Annual	31	19	--	--
	Highest 24-hr	130	166	--	--
	2nd Highest 24-hr	129	164	--	--
	Highest 3-hr	227	218	--	--
	2nd Highest 3-hr	218	201	--	--
New Haven	Annual	32	45	42	35
	Highest 24-hr	176	239	207	205
	2nd Highest 24-hr	166	214	178	176
	Highest 3-hr	343	333	359	359
	2nd Highest 3-hr	307	279	293	298
Waterbury	Annual	23	35	25	21
	Highest 24-hr	126	180	163	103
	2nd Highest 24-hr	122	140	111	97
	Highest 3-hr	372	393	266	205
	2nd Highest 3-hr	211	236	217	175
New Britain	Annual	26	21	23	20
	Highest 24-hr	166	150	163	122
	2nd Highest 24-hr	138	149	105	90
	Highest 3-hr	326	256	259	190
	2nd Highest 3-hr	231	197	190	162
Derby	Annual	19	35	--	--
	Highest 24-hr	105	149	--	--
	2nd Highest 24-hr	99	136	--	--
	Highest 3-hr	253	159	--	--
	2nd Highest 3-hr	231	150	--	--
Hartford	Annual	30	39	36	39
	Highest 24-hr	213	173	178	200
	2nd Highest 24-hr	170	167	163	193
	Highest 3-hr	364	274	265	343
	2nd Highest 3-hr	296	233	261	290
Middletown	Annual	29	35	--	--
	Highest 24-hr	89	207	--	--
	2nd Highest 24-hr	85	125	--	--
	Highest 3-hr	161	258	--	--
	2nd Highest 3-hr	153	236	--	--

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[a] Non-overlapping running averages.

[b] Monitors in Northeast Utilities local SO_2 monitoring system.

TABLE 3-11

YEARLY SUMMARY OF AVAILABLE PARTICULATE MATTER AMBIENT AIR QUALITY DATA IN THE VICINITY OF MT. TOM GENERATING STATION[a]

(Concentrations in $\mu g/m^3$)

Location	Averaging Period	1977	1978	1979	1980
Chicopee[b] Trailer (CT)	Annual	--	95	--	--
	Highest 24-hr	--	178	--	--
	2nd Highest 24-hr	--	162	--	--
Chicopee[c] City Hall (CCH)	Annual	49	--	60	65
	Highest 24-hr	178	152	184	141
	2nd Highest 24-hr	131	117	109	106
Springfield[d] Howard St. (SH)	Annual	--	--	58	58
	Highest 24-hr	--	203	304	237
	2nd Highest 24-hr	--	167	151	185
Springfield Mill St. (SM)	Annual	55	54	60	70
	Highest 24-hr	187	152	141	155
	2nd Highest 24-hr	129	124	137	92
Springfield Taylor St. (ST)	Annual	60	63	61	68
	Highest 24-hr	154	176	156	127
	2nd Highest 24-hr	126	120	140	115
Springfield[e] Civic Center (CC)	Annual	--	--	49	50
	Highest 24-hr	122	143	136	171
	2nd Highest 24-hr	108	142	129	168
East Springfield (ES)	Annual	--	--	56	61
	Highest 24-hr	133	115	136	169
	2nd Highest 24-hr	86	111	125	157
Springfield Long Hill (LH)	Annual	--	--	51	54
	Highest 24-hr	108	114	112	137
	2nd Highest 24-hr	75	111	101	134
Holyoke[f] Cabot St. (HC)	Annual	--	61	60	61
	Highest 24-hr	--	140	157	131
	2nd Highest 24-hr	--	133	153	116
Northampton (N)	Annual	--	--	53	54
	Highest 24-hr	107	98	143	127
	2nd Highest 24-hr	63	97	118	120

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[a] Does not include sites for which the data record is 3 months or less. Special study site, 1978.

[b] Site environment being assessed for possible undue local impacts.

[c] Site closed down 1980 (site did not meet Federal guidelines).

[d] Special study site, 1978: 74 samples; 1979: 326 samples; 1980: 321 samples.

[e] Sampling conducted daily.

[f] Special study site, 1978; 111 samples. Closed down 1980 (height inconsistent with Federal guidelines).

A brief discussion of the ambient (preconversion) levels of each of the pollutants presented in Tables 3-9, 3-10, and 3-11 is given below.

Sulfur Dioxide (SO_2). Considerable variation from year to year is seen in these data, but no consistent trend is apparent. None of the SO_2 ambient levels approach the NAAQS or, the MAAQS shown in Table 3-12.

Particulate Matter (PM). Annual average concentrations that exceed the standard of 75 g/m^3 have been recorded at one monitor in Chicopee, and also much farther from Mt. Tom at Waterbury and New Haven in Connecticut. The Chicopee monitor showing nonattainment of the PM NAAQS is located approximately 10 km (6 miles) south of the Mt. Tom generating station.

Ozone (O_3). Every O_3 monitor in AQCR 42 detected concentrations in excess of the NAAQS. Only data from the closest stations to Mt. Tom, at Amherst and Agawam, are presented in Table 3-9.

Carbon Monoxide (CO). The nearest monitor to Mt. Tom was in Springfield. Because CO concentrations are predominantly due to automotive traffic in urban areas, the ambient data shown are not representative of the immediate vicinity of the Mt. Tom generating station, and are presumably much higher than near Mt. Tom.

Nitrogen Dioxide (NO_2). The nearest continuous monitor of NO_2 was in Springfield. Because automotive traffic is a significant contributor to ambient NO_2 levels, it is expected that the level shown is higher than would be measured near Mt. Tom.

Lead (Pb). Pb concentrations in excess of the NAAQS have been measured in Springfield, approximately 20 km south of Mt. Tom, as well as much farther away in Hartford and New Haven. No attainment/nonattainment area designations have been made for Pb, so it does not appear in Table 3-13. However, the Federal Register announcement of the SIP requirements for the Pb NAAQS attainment program (43 FR 46264, 5 October 1978), indicates Waterbury, Connecticut, and Springfield-Chicopee-Holyoke, Massachusetts, as "Urbanized Areas with Lead Air Concentrations Exceeding or Equal to 1.5 g/m^3, Maximum Quarterly Mean (1975)" in AQCR 42. The Pb concentrations measured in Springfield are most likely predominantly due to local particulate matter sources, especially wind-entrained roadway dust.

Sulfate. An unknown fraction of ambient sulfate particles may be transported from far-upwind SO_2 sources. Therefore the measured values can be taken to be representative of the region. Note that the two different measuring techniques at the Chicopee site produced very different results. Currently, there exist no ambient standards for sulfates.

Nitrate. The comments made above for sulfates also apply to nitrates.

Trace Metals. No ambient standards exist for these pollutants, but possible chronic toxic effects due to long-term human exposure to low concentrations of these metals is currently being actively investigated. Local concentrations of these pollutants may be affected by fossil fuel combustion.

Occupational Safety and Health Administration (OSHA) work-place concentration limits do exist for each of the trace metals listed in Table 3-9, and these limits are indicated for comparison with the observed ambient concentrations in Springfield. The maximum 24-hour ambient concentrations are several orders of magnitude below the OSHA 8-hour limits.

3.3.3 Applicable Air Pollution Standards and Classification

National primary and secondary Ambient Air Quality Standards for sulfur oxides, suspended particulate matter, carbon monoxide, nitrogen dioxide, and photochemical oxidants, along with a guideline value for hydrocarbons were promulgated by EPA on April 13, 1971. A National Ambient Quality Standard for lead was promulgated on October 5, 1978, and the photochemical oxidant standard was revised to an ozone standard on February 8, 1979. These are minimum standards that all states were required to enforce.

Primary standards are intended to protect public health, with an adequate margin of safety, while secondary standards are defined levels of air quality intended to protect

TABLE 3-12

NATIONAL AND MASSACHUSETTS AMBIENT AIR QUALITY STANDARDS (FEBRUARY 1981)

(Concentrations in $\mu g/m^3$)

Pollutant	Averaging Time	National[a]		Massachusetts[a]	
		Primary	Secondary	Primary	Secondary
Sulfur dioxide (SO_2)	3 hrs	--	1,300	--	1,300
	24 hrs	365	--	365	--
	Annual	80	--	80	--
Particulate Matter (PM)	24 hrs	260	150	260	150
	Annual	75	60[b]	75	--
Carbon monoxide (CO)	1 hr	40,000	40,000	40,000	40,000
	8 hrs	10,000	10,000	10,000	10,000
Hydrocarbons[c] (HC)	3 hrs	160	160	160	160
Nitrogen dioxide (NO_2)	Annual	100	--	100	100
Sulfate		No Standards			
Ozone (O_3)[d]	1 hr	235	235	235	235
Lead (Pb)	Calendar Quarter	1.5	--	1.5	--

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[a] National and Massachusetts standards other than those based on annual arithmetic means or annual geometric means are not to be exceeded more than once per year.

[b] Guideline value.

[c] Three hour maximum concentration from 6:00 a.m. to 9:00 a.m. to be used as a guideline for assessing implementation plans. EPA has proposed a rule making, as of 8 May 1981, to revoke the HC NAAQS, because no adverse health effects due to exposure to HC as a class have been demonstrated.

[d] Standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above 235 $\mu g/m^3$ is equal to or less than one.

TABLE 3-13

AIR POLLUTION ATTAINMENT STATUS OF AREAS WITHIN AIR QUALITY CONTROL REGION 42

SECTION A

Pollutant	Area	Better Than National Standards	Cannot Be Classified	Does Not Meet Primary Standards	Does Not Meet Secondary Standards
SO_2	Massachusetts (PVAPCD)	X			
	Connecticut (AQCR 42)	X			
PM	Massachusetts (PVAPCD)				
	Springfield			X	
	Chicopee		X		
	Holyoke		X		
	Northampton		X		
	South Hadley		X		
	West Springfield		X		
	All Other Cities and Towns	X			
	Connecticut (AQCR 42)			X	

SECTION B

Pollutant		Cannot be Classified Or Better Than National Standards	Does Not Meet Primary Standards
O_3	Massachusetts (PVAPCD)		X
	Connecticut (AQCR 42)		X
NO_2	Massachusetts (PVAPCD)	X	
	Connecticut (AQCR 42)	X	
CO	Massachusetts (PVAPCD)		
	Springfield		X
	All Other Cities and Towns	X	
	Connecticut (AQCR 42)		X

the public welfare from any known or anticipated adverse effects. The applicable Massachusetts (MAAQS) and National (NAAQS) standards are summarized in Table 3-12. In addition to these standards, DEQE enforces a policy on short-term NO_2 concentrations.

The policy requires that new or modified major sources of NO_2 that increase NO_x emissions by more than 250 tons per year demonstrate that the operation of the source will not, with consideration of background, cause or significantly contribute to NO_2 concentrations (at specified points of concern) in excess of 320 $\mu g/m^3$ for any 1-hour period on more than 1 day per year.

The classification of attainment status for the pollutants listed in Table 3-12 for the AQCR 42 is presented in Table 3-13. The Massachusetts portion of AQCR 42 is called the Pioneer Valley Air Pollution Control District (PVAPCD). The attainment status classifications are as follows:

1) For SO_2 and particulate matter (PM) (Section A of Table 3-13), the classes are:

   ° Better than national standards

   ° Does not meet primary standards

   ° Does not meet secondary standards

   ° Cannot be classified.

2) For nitrogen dioxide (NO_2), ozone (O_3), and carbon monoxide (CO) (Section B of Table 3-13), the classes are:

   ° Does not meet primary standards

   ° Cannot be classified, or better than national standards.

It is seen from Table 3-13 that the entire AQCR is attainment for SO_2 and NO_2, and nonattainment for O_3. Parts of the AQCR are nonattainment for PM and for CO, but the Mt. Tom generating station is not located within any of the nonattainment areas. The information in Table 3-13 was taken from 43 FR 8977 (3 March 1978), 43 FR 9002-9003 (3 March 1978), 43 FR 40423 (11 September 1978), and 43 FR 40426-40427 (11 September 1978).

In addition to ambient air quality standards, EPA also has promulgated performance standards that regulate pollutant emission rates from certain classes of new or modified stationary sources. However, an electric generating station that switches to coal fuel as a direct result of a Prohibition Order under Section 2(a) of ESECA is not considered to be a new source or a modification of an existing source for the purposes of application of Federal New Source Performance Standards (Section 111(a)(8) of the Clean Air Act (CAA) as amended August 1977). An ESECA-ordered fuel conversion is also explicitly excluded from the definition of a source modification for the purposes of the nonattainment area provisions of the Clean Air Act (CAA Section 171) and the Prevention of Significant Deterioration (PSD) provisions (CAA Section 196(2)(c). In addition, the emissions from an ESECA-ordered fuel conversion source may be excluded from consumption of the PSD increments for a period of up to 5 years (CAA Section 163(c)). This latter exclusion requires an order from the governor of the state, a State Implementation Plan (SIP) that is either approved or pending approval by the EPA, and a determination by the EPA that the order satisfies the requirements of the CAA.

Regardless of the exclusion of the Mt. Tom generating station from the laws and regulations mentioned in the previous paragraph, the station must be in compliance with applicable emission regulations as stipulated in the SIP. The SIP applied to Mt. Tom generating station prior to the reconversion restricted PM emissions to 0.12 pound per million Btu heat production, and limited the amount of sulfur in the fuel to no more than 1.21 pounds per million Btu heat production; this SIP was approved by EPA on 2 October 1979 (44 FR 56694). A revised SIP has been approved by EPA Region I to become effective August 9, 1982 (47 FR 25007-25008). This revision limits the PM emissions to 0.08 pound per million Btu heat input, but does not change the sulfur-in-fuel content. Because the Mt. Tom station is operating under a DCO, the change does not become effective until February 15, 1984 (see Appendix C).

The MOU signed in March 1980 and the DCO issued in November 1981 concerned certain agreements with respect to a Mt. Tom generating station conversion to coal fuel. The particular coal conversion outlined in the MOU is assumed to be the response to an NOE that is preferred by the parties to the MOU. The MOU/DCO coal conversion involves changes in the air pollution standards applicable to the Mt. Tom generating station during two distinct periods of time:

1) An interim period during which the station will burn coal using the currently existing PM control equipment, with appropriate repairs and modifications.

2) A final period following the installation of a new and upgraded PM control system.

The emission standards during the interim period are stipulated by the DCO, and the emission standards during the final period will be stipulated by a revised SIP. The standards during the two periods are described below.

During the first 8 months of coal burning under the DCO, PM emissions will be 0.48 pound per million Btu heat production, and the sulfur-in-fuel limitation will be 1.21 pounds per million Btu heat production, with compliance based on a running 30-day average of sulfur-in-fuel, and a 24-hour limit of 1.60 pounds per million Btu heat production. For the remainder of the DCO, PM emissions must be limited to 0.35 pound per million Btu. The DCO is primarily designed to permit an increase in the PM emissions above the 0.12 pound per million Btu limit of the SIP which was in effect when the DCO was issued. Except for the provision of potential increased maximum 24-hour SO_2 emissions (but which nonetheless must meet the SIP for any 30-day period), the sulfur-in-fuel limitation is not larger than that of the SIP.

A coal conversion under an ESECA prohibition order is specified in Section 113(d)(5)(A) of the CAA as a candidate for a DCO if the subject source, in responding to the prohibition order, would thereby no longer be in compliance under the applicable implementation plan. The DCO issued by EPA Region I for the Mt. Tom coal conversion contained the following requirements on the source, pursuant to paragraphs (A) through (D) of Section 113(d)(5) of the CAA:

1) A stipulated period of time for the source to come into compliance with the SIP, which should be as short as practicable, but in any case no longer than 5 years.

2) Prescription of emission limitations, requirements respecting pollution characteristics of coal, or other enforceable measures for control of emissions as needed to assure that the burning of coal by the source will not result in emissions which cause or contribute to any violation of the national primary ambient air quality standards (primary NAAQS).

The DCO for the MOU coal conversion was requested with respect to emissions of PM from the source during the period of time between the initial burning of coal and the installation of improved control equipment. Near the Mt. Tom site is the city of Springfield, which has been designated under CAA Section 107(d) as a nonattainment area of the PM primary NAAQS. (Table 3-13 presents the attainment status for all criteria pollutants within the PVAPCD.) Because of this nonattainment area, the issuance of the DCO depended upon an air quality analysis performency that demonstrated the following (CAA Section 113(d)(5)(D)):

1) That PM emissions from the source will affect only infrequently the air quality concentrations of PM in each portion of the nonattainment area.

2) That PM emissions from the source will have only insignificant effect on the PM concentration in each portion of the nonattainment area.

3) Reasonable statistical assurance that emissions of PM from the source will not cause or contribute to PM concentrations in excess of the national primary ambient air quality standard.

Provision of this demonstration constitutes a "rebuttal of regional limitation."

It is noted that the objective of the air quality analysis required for the DCO is a demonstration that the primary NAAQS are not jeopardized by the source. It is not necessary to demonstrate compliance with the secondary NAAQS.

Following the interim period, the low-sulfur coal conversion must meet the following standards:

1) PM emissions will not exceed 0.08 pound per million Btu heat input.

2) Sulfur-in-fuel limits will be as given for the interim period.

This PM standard has been approved by EPA Region I. The SIP emission standards applicable to the Mt. Tom generating station and the changes in the standards under the low-sulfur coal conversion scenarios are tabulated in Table 3-14.

TABLE 3-14

ANTICIPATED AIR POLLUTANT LIMITATIONS - LOW-SULFUR COAL CONVERSION

Controlling Regulation	Particulate Matter Emission Limit[a]	Sulfur-in-Fuel Limit[b]	
		30-Day Average	24-Hour Maximum
Old SIP[c]	0.12	1.21	---
DCO	0.48	1.21	1.60
New SIP	0.8	1.21	1.60

[a] In units of pounds particulate matter per million Btu heat input.

[b] In units of pounds sulfur per million Btu heat production.

[c] Reference is to SIP in effect when DCO was issued.

The low-sulfur coal conversion would not be subject to PSD review because of its status as an ESECA-mandated fuel conversion, as discussed above. Also, because the Mt. Tom generating station is located in an area for which the PSD baseline date has not been established, any increases in actual PM or SO_2 emissions at Mt. Tom due to the fuel conversion would not consume PSD increment. However, the changes in the SIP could consume increment in a nearby region for which the PSD baseline date has been established. This region includes the town of South Hadley, directly across the Connecticut River from the Mt. Tom site. The reduction in allowed Mt. Tom PM emission rate from 0.12 pound per million Btu to 0.08 pound per million Btu will expand the available PM PSD increment in South Hadley and the remainder of this region. The explicitly higher allowed 24-hour SO_2 emission rate in the SIP revision will not affect PSD increment consumption, because the previous SIP has been interpreted by the Commonwealth of Massachusetts as appropriate to a 30-day rolling averaging period, and not to any arbitrarily small averaging time. Because the revised SIP does not relax allowed SO_2 emissions for any 30-day period, the SIP revision does not consume PSD increment. This interpretation conforms to that stated by EPA in its approval of a similar SIP revision for a coal conversion at the Brayton Point generating station (44 FR 12459-12461, 5 March, 1979). Also, in EPA's notice of proposed ruling on the DCO request, this interpretation was explicitly acknowledged; therefore, no SO_2 analysis for the DCO was performed for this EIS on the strength of the interpretation (46 FR 39168).

The DCO as issued by EPA differs in some details from the DCO envisioned in the MOU. The primary differences from the point of view of this section are that the EPA DCO does not address SO_2 emissions, and that increased control (to a limit of 0.35 lb PM/10^6 Btu) of PM emissions is required in the DCO period after 8 months following initiation of coal burning. Further details are provided in the Federal Register announcement (46 FR 57493, 24 November 1981) (see Appendix C).

3.4 BIOLOGY

3.4.1 Aquatic Biology

There are two aquatic systems which are affected by the Mt. Tom generating station: Kennedy Brook, a small stream which crosses the property between the ash pond sites, and the Connecticut River.

3.4.1.1 Kennedy Brook

Kennedy Brook, a small tree-lined stream, bisects the Mt. Tom site from west to east. Kennedy Brook provides overflow drainage for nearby Kennedy Pond into the Connecticut River. The brook does not provide a significant nursery area for larval fish. It has steep sides, and the flow appears to fluctuate substantially. When visited during July 1981 there was very little flow in Kennedy Brook at all. The brook does provide a type of habitat (rocky stream bed and banks) not found elsewhere on the site. No construction or operation activities are planned which should impact Kennedy Brook.

3.4.1.2 Connecticut River

This section of the Connecticut River is regarded as Class B water. Class B water is suitable for swimming and recreation, fishing, agricultural and industrial purposes, and if properly treated, for consumption. This section of the river is slow flowing and subject to considerable fluctuation due to alteration of the river flow by the Turners Falls dam upstream and the Holyoke dam downstream for hydroelectric generating purposes.

The Mt. Tom generating station is located on the Holyoke pool, the section of the river lying between the Holyoke Water Power Company dam (5.5 river miles downstream of the station) and the Turners Falls dam (32 miles upstream of the station). Slack water impounded by the Holyoke dam occasionally influences the river at the station site.

The Mt. Tom plant presently takes in about 133 MGD of water for cooling plant condensers. This water is then discharged back into the river at a temperature not to exceed 32°F above the ambient river temperature. The discharge water cannot exceed 102°F in accordance with standards set by the Division of Water Pollution Control and the Environmental Protection Agency. The plant also adds chlorine once daily as a biocide to river water passing through the condensers. This is to prevent aquatic growths from building up in the water circulating systems. The water is returned directly to the river, and the concentration of chlorine in the effluent is limited to 0.1 ppm by EPA regulations.

Fish samples taken at the Mt. Tom site (June to October, 1974) indicate that the most common resident species are white sucker, channel catfish, carp, white perch, bluegill, small-mouth bass, crappies, yellow perch, and spottail shiner. The Connecticut River contains the only fishery for walleye and northern pike in the state. Migratory species at the site include: American shad, blueback herring, sea lamprey, American eel, and Atlantic salmon. Except for the American eel, these fish attain most of their growth in the ocean and migrate up river to spawn. The American eel attains most of its growth in fresh water and migrates downstream to spawn in the ocean. Table 3-15 lists the fish lifted over the Holyoke dam and the fish sampled at the Mt. Tom site (Henry and others, 1974).

Prior to the year 1800, the Connecticut River supported large runs of Atlantic salmon and shad. Dams built on the lower Connecticut River eliminated the Atlantic salmon runs completely by cutting off access to spawning grounds on tributaries. Dam construction drastically reduced shad runs, but some spawning areas (in the main channel of the Connecticut River) still remain.

In 1966, fishery agencies in four New England States (Connecticut, Massachusetts, New Hampshire, and Vermont) and regional offices of the U.S. Fish and Wildlife Service and the National Marine Fisheries Service, initiated a major effort to restore these fish runs. The Connecticut River Anadromous Fish Restoration Program is designed to restore 2 million American shad and 40 thousand Atlantic salmon annually to the river's mouth (U.S. Fish and Wildlife Service, 1977) by installing fishways in the various dams and by stocking riverside pools with juvenile salmon at the appropriate season. Returning adult salmon passing the Holyoke dam (Connecticut River) and the Rainbow dam (Farmington River, a Connecticut River tributary) increased from only a few in 1976/77 to over 300 in 1981; migrating shad increased from 4,899 in 1955 to 376,761 in 1981. Approximately 5,000 shad died at the base of the Turners Fall dam in 1976; Reed (U.S. Fish and Wildlife Service, 1977) reported that construction of fishways at Turners Falls dam was scheduled for completion in 1980.

Most of the shad spawning areas are in the upper portion of the Holyoke pool, but a recent study by Kuzmeskus (1977) has identified additional spawning areas along the eastern shore of the river both directly opposite the generating station site and about a mile downstream.

TABLE 3-15

FISH SAMPLED AT THE HOLYOKE DAM AND AT THE MT. TOM GENERATING STATION

Common Name	Scientific Name	Numver Lifted Over Holyoke Dam 1975-1976[a]	Number Samples at Mt. Tom[b] Summer 1974		Number of Fish Impinged at Mt. Tom[b] Summer 1974
			In Thermal Plume	Outside Thermal Plume	
Sea lamprey	*Petromyzon marinusum*	55,470			
Shortnose sturgeon	*Acipenser brevirostrum*	8			
American eelnfish	*Anguilla rostrata*	861			1
Blueback herring	*Alosa aestivalis*	6,383			1
American shad	*Alosa sapidissima*	462,458			
Rainbow trout	*Salmo gairdneri*	161			
Atlantic salmon	*Salmo salar*	5[c]			
Brown trout	*Salmo trutta*	146			
Brook trout	*Salvelinus fontinalis*	32			
Northern pike	*Esox lucius*	7			
Goldfish	*Carassius auratus*	1			
Carp	*Cyprinus carpio*	108	9	3	
Golden shiner	*Notemigonus cryeoleucae*	130			
Common shiner	*Notropus cornutus*	44			
Spottail shiner	*Notropus hudsonius*	15,611	21	2	1
Blacknose dace	*Rhinichthys atratulus*	4			
Fallfish	*Semotilus corporalis*	1			
White sucker	*Catostomus commersoni*	6,476		3	
Brown bullhead	*Ictalurus nebulosus*	136			7
Yellow bullhead	*Ictalurus natalis*	1			
Channel catfish	*Ictalurus punctatus*	4,537	4	2	16
White catfish	*Ictalurus catus*				1
White perch	*Morone americana*	1,997	22	1	1
Rock bass	*Ambloplites rupestris*	54			
Redbreast sunfish	*Lepomis auritus*	3			
Pumpkinseed	*Lepomis gibbosus*	173		2	1
Bluegill	*Lepomis macrochirus*	1,030	4	7	
Longear sunfish	*Lepomis megalotis*	1			
Smallmouth bass	*Micropterus dolomieui*	1,661	7	5	
Largemouth bass	*Micropterus salmoides*	178		1	
White crappie	*Pomoxis annularis*	4	3	1	
Black crappie	*Pomoxis nigromaculatus*	596	5	2	1
Yellow perch	*Perca flavescens*	369	1	21	15
Walleye	*Stizostedion vitreum vitreum*	78			
Total		588,722			

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[a] Sources: Table 1, Biennial Report, January 1, 1975 - December 31, 1976. Connecticut River Anadromous Fish Restoration Program, U.S. Fish and Wildlife Service, 451 Russel St., Hadley, Massachusetts; Tables 9 and 10, Thermal Plume Study of the Mt. Tom Plant of Holyoke Water Power Company , by Stephen M. Henry, Richard Robillard, and Richard Turek, Massachusetts Division of Fishersies and Wildlife, Westboro, Massachusetts, 1974; Table 12 of refrence in (b). Numbers represent total number collected in eighteen 24 hour samples taken once a week.

[b] Henry and others, 1974.

[c] Includes two downstream-migrating juveniles.

[d] Table 1, U.S. Fish and Wildlife Service, 1976.

3.4.2 Terrestrial Biology

3.4.2.1 Flora

An aerial survey conducted in 1971 (MacConnell, 1975a,b) shows the land within a one mile radius of the station to be 58 percent wooded, 8 percent agricultural, 10 percent abandoned fields, 3 percent residential, and 20 percent other uses, including highways and a golf course.

The wooded areas are predominantly hardwoods; only 15 percent of the wooded areas consist of stands where softwoods predominate. Mountainous wooded lands (with elevations up to 1,000 feet) flank the Mt. Tom generating station to the northeast and southwest. The southwest area adjacent to the station is part of the Mt. Tom Reservation, a park providing picnicking and hiking.

The generating station occupies an 89-acre tract at the north end of a narrow strip of land between U.S. Highway 5 and the Connecticut River. The plant, railroad sidings, a coal pile, and ash ponds cover most of the site. Several acres of utility-owned land immediately south of the site are now leased and planted in corn, but could, if permitted, eventually be converted into an additional ash disposal site. Old ash pond sites, unused since 1970 when the station converted to oil, supported many young quaking aspen prior to the recent reconversion construction; the oldest pond site, filled in 1962 and covered with 2 inches of loam, had young aspen trees 10 to 20 feet tall. Cottonwood, oak, and maple trees line both the river and Kennedy Brook.

3.4.2.2 Fauna

The Connecticut River valley is part of the Atlantic Flyway, a major route for migrating birds (e.g., hawks, warblers, Canada geese, common merganser, black duck, and mallard duck), which may visit either the generating station or the adjacent lands. However, river meanders, old oxbows upstream of the station, and the nearby 475 acre Audubon Society Arcadia Wildlife Sanctuary provide much more extensive waterfowl habitat.

Likely summer bird residents on the site include the song sparrow, redwing blackbird, eastern kingbird, brown thrasher, catbird, and yellow warbler.

Game mammals that might be present on the site include the eastern cottontail rabbit, woodchuck, gray squirrel, muskrat, raccoon, longtailed weasel, mink, river otter, fox, and white-tailed deer.

3.4.3 Threatened or Endangered Species; Unique or Critical Habitats

The Mt. Tom generating station site itself contains no unique plant or animal communities, although important habitats exist nearby. River meanders and oxbows upstream of the station site provide important wetland habitat. The Audubon Society's Arcadia Wildlife Sanctuary is approximately 2 miles northwest of the generating station, next to an oxbow still connected with the river. The Holyoke Range provides a habitat for bobcats, and represents a potentially important habitat for wild turkeys and peregrine falcons. Both wild turkeys and peregrine falcons were once common in this part of Massachusetts. The increasing activities of humans have reduced the numbers of these species, partially through alteration of habitats. Both falcons and wild turkeys occur in the Holyoke Range today. The Holyoke pool of the Connecticut River provides an important habitat for both migrant and resident fish, including endangered species (discussed in the following paragraphs).

Table 3-16 lists the threatened and endangered species known to occur in the vicinity of the generating station; three species (falcon, eagle, and sturgeon) are on the Federal list of endangered species. The shortnose sturgeon is a large but slow-growing bottom-feeding fish found in tidal rivers along the East Coast from the St. John River in New Brunswick to the St. Johns River in Florida (Scott and Crossman, 1973). Although it is not abundant anywhere along the East Coast now, it probably used to be abundant from the Connecticut to the Potomac Rivers. The Holyoke pool of the Connecticut River contains one of the few known viable populations of this fish, although general fish surveys are unlikey to locate small sturgeon populations. Further efforts to locate this species specifically may reveal it to be more prevalent than presently believed; such searches below the Holyoke pool are just beginning.

TABLE 3-16

THREATENED AND ENDANGERED SPECIES OCCURRING IN THE VICINITY OF THE MT. TOM GENERATING STATION

Species	Scientific Name	Massachusetts Status[a]	Notes
Shortnose sturgeon	*Acipenser brevirostrum*	Rare and endangered[b]	
Atlantic salmon	*Salmo salar*	Rare and endangered	
White catfish	*Ictalurus catus*	Rare and depleted	Introduced
Channel catfish	*Ictalurus punctatus*	Rare	Introduced
White crappie	*Pomoxis annularus*	Rare and depleted	Introduced
Longear sinfish	*Leopmis megalotis*	Rare and depleted	Introduced
Walleye	*Stizostedion vitreum vitreum*	Rare	Introduced
Northern pike	*Esox lucius*	Rare	Introduced
Bald eagle	*Haliaeetus leucocephalus*	Endangered[b]	Migrants regularly at Mt. Tom
Peregrine falcon	*Falco peregrinus*	Endangered[b]	Experimental release program currently inactive
Timber rattlesnake	*Crotalus horridus horridus*	Endangered	Rocky outcrops of the Holyoke Range
Marbled salamander	*Ambystoma opacum*	Threatened	Mt. Tom area
Spotted salamander	*Ambystoma maculatum*	Threatened	Statewide distribution

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[a] Rare - not under immediate threat of extinction but occurring in such a small number of restricted habitats that it could quickly disappear.

Endangered - actively threatened with extinction in the state.

Depleted - although still occurring in numbers adequate for survival, the species has been heavily depleted and continues to decline at a rate substantially greater than can be sustained.

Threatened - likely to become an endangered species in the foreseeable future throughout all or at significant portion of its range.

[b] Also on the Federal list of endangered species.

Source: Mugford, 1976.

Little is known about the early life stages or the migratory habits of this sturgeon, except that it spawns in fresh water in the spring and that adults are occasionally found in salt water as well as fresh water. Information from current studies of shortnose sturgeon populations in the Hudson, St. John, and Connecticut Rivers is not yet available, but preliminary data for the Holyoke pool (U.S. Fish and Wildlife Service, 1977) show 66 fish collected and tagged in 1976. The fish ranged in size from 17 to 41 inches total length. Most were found in regions either 2 or 8 miles upstream of the Mt. Tom generating station, although some were collected downstream of the station. Representativeness of this sample remains undetermined. Shortnose sturgeon eggs have been found near the site of the intake for a formerly proposed nuclear plant in the upstream end of the Holyoke Pool, but their migratory runs appear to be irregular. A few shortnose sturgeon have been found in the Holyoke dam fish lift - eight during 1975-1976 (Table 3-16) - but some years none are observed.

The peregrine falcon at one time nested in the vicinity of the Mt. Tom station. This species, listed as endangered by the U.S. Fish and Wildlife Service, coexists well with man. However, nesting success of this species was severely restricted because of accumulations of the pesticide DDT in falcon eggshells. As levels of DDT in the environment decrease falcons are making a comeback. The U.S. Fish and Wildlife Service has undertaken an experimental release program in the vicinity of the Mt. Tom site. Falcons reared in captivity have been released into the wild in hopes of establishing a new breeding population in the area. However, this program has been currently discontinued.

The bald eagle (endangered) is threatened by its lack of reproductive success, due to human disturbance at nesting sites and harmful accumulations of pesticides. It does not presently nest in Massachusetts although it is found in the Mt. Tom area year round. The timber rattlesnake was originally abundant in Massachusetts but has been all but eradicated as the state has become more populated. The two woodland salamanders, the marbled and the spotted, both are native to the deciduous forest surrounding the station. However, as this habitat becomes less common, these species are declining in abundance. Presently, the marbled salamander population at the Mt. Tom Reservation, just southwest of the Mt. Tom generating station site, is one of the only three known breeding populations in Massachusetts.

The Atlantic salmon is listed as rare and endangered by the state of Massachusetts. Once very common in coastal rivers, this species has been severely reduced in numbers by the building of dams, which block its migratory runs. Through an extensive management effort salmon are beginning to return to Massachusetts (Section 3.4.1.2).

The remainder of the species listed in Table 3-16 are placed by the state in the categories of rare, or rare and depleted. Although species listed are not presently in danger of extinction, the populations are such that concern about their ability to survive in the future is expressed by the state, but no other regulatory action is taken.

3.5 SOCIOCULTURAL RESOURCES

3.5.1 Population and Land Use

3.5.1.1 Population

The communities of the lower Pioneer Valley (Hampden and Hampshire Counties, see Figure 3-14) can be divided into four categories: urban core, sub-regional centers, suburban fringe, and rural fringe. For each category, Table 3-17 gives population, share of regional population, and 1960 to 1970 growth rate. Note that the 15 suburban communities grew the fastest while the urban core areas declined in population. Regional land use is shown in Figure 3-12.

3.5.1.2 Regional Land Use

Agriculture still plays an important role in the region. Much of the land in the lower Connecticut Valley is used for growing shade tobacco, asparagus, and onions, and there are dairy farms in the upland areas.

Several studies which were authored by the Lower Pioneer Valley Regional Planning Commission have indicated that the region is running out of good developable land for future urban expansion. The effect of this shortage may result in two undesirable situations: (1) marginal land will be pressed into development which will result in higher

TABLE 3-17

GROWTH RATE BY CATEGORY OF COMMUNITY IN THE LOWER PIONEER VALLEY REGION

Type of Community	Number of Communities	1970 Population	% of 1970 Regional Population	% Population Change 1960-1970
Urban core	3	281,000	48	-3
Sub-regional Center	5	107,000	18	22
Suburban (fringe)	15	170,000	30	27
Rural (fringe)	20	25,000	4	15
Total	43	583,000	100	10

Source: Lower Pioneer Valley Regional Planning Commission, 1977.

TABLE 3-18

LAND USE IN THE MT. TOM AREA

Use	Communities Within 5-Mile Radius[a] (% of Total Area)	Lower Pioneer Valley Region (% of Total Area)
Urban	20.5	12.0
Industrial	1.1	0.5
Heavy Residential	3.9	1.8
Light Residential	10.9	7.0
Commercial	1.2	0.6
Other Urban	3.4	2.1
Forest	44.2	67.8
Agriculture and Open Land	27.1	15.0
Wetland	5.7	3.9
Mining and Waste Disposal	0.6	0.4
Outdoor Recreation	1.9	0.9
	100	100
Total Number of Acres (square miles)	74,000 (116)	751,000 (1175)

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[a] Includes Holyoke, Northampton, Easthampton, Hadley, and South Hadley.

Source: MacConnell, 1975.

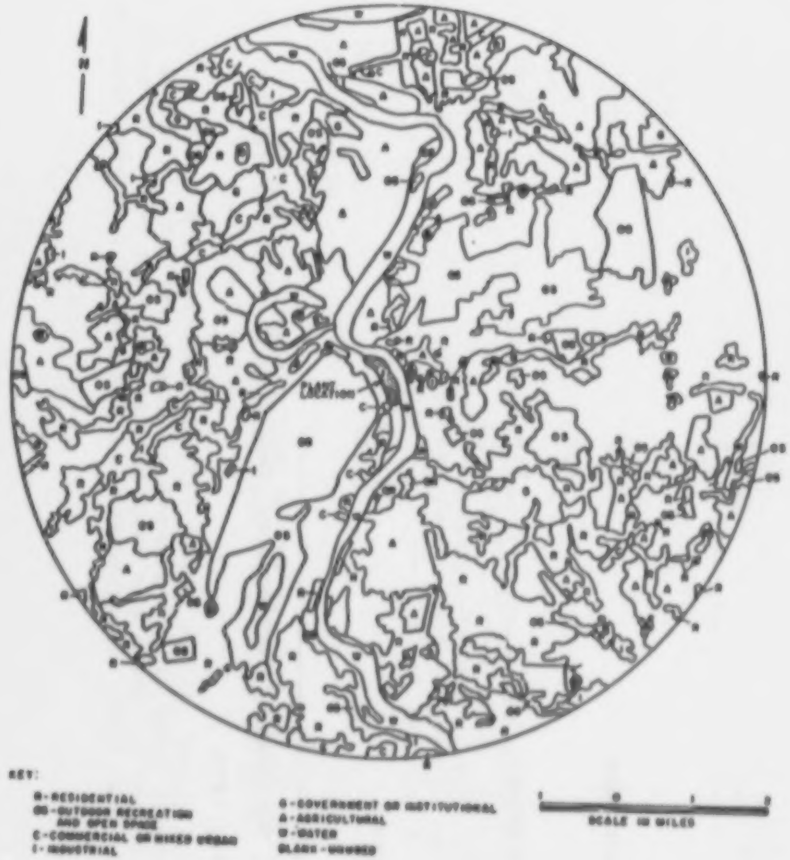
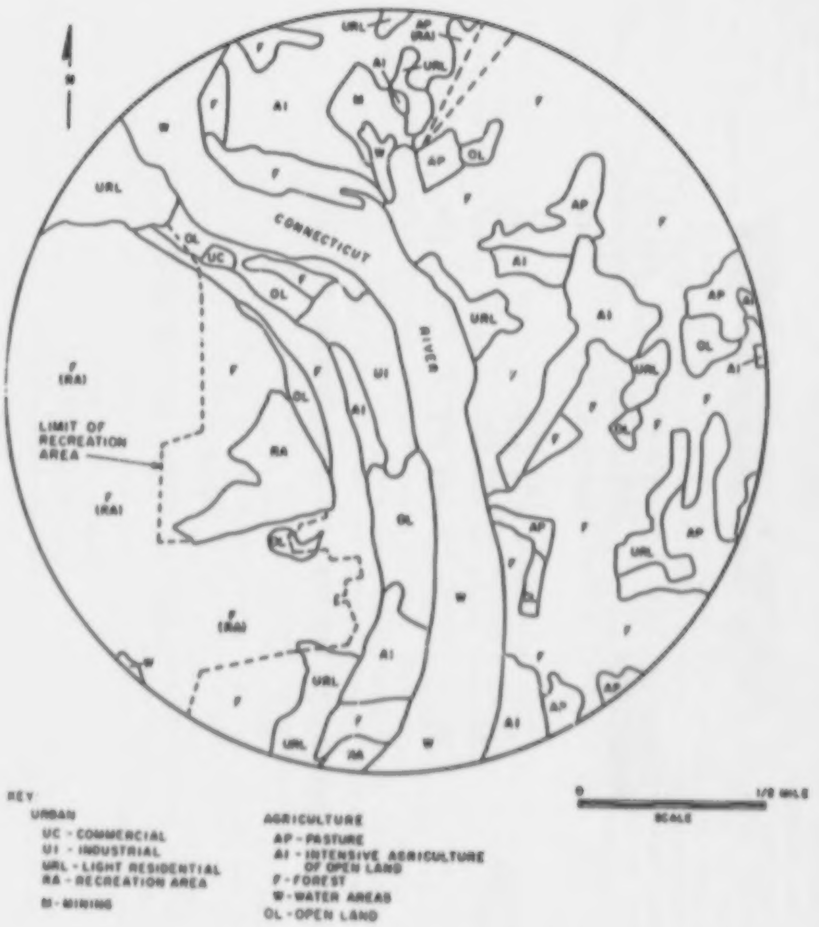

N
PLANT LOCATION
KEY:
R - RESIDENTIAL
OS - OUTDOOR RECREATION AND OPEN SPACE
C - COMMERCIAL OR MIXED URBAN
I - INDUSTRIAL
G - GOVERNMENT OR INSTITUTIONAL
A - AGRICULTURAL
W - WATER
BLANK - UNUSED
1
0
1
2
SCALE IN MILES

Figure 3-12. Land Use Within Five Miles of the Mt. Tom Generating Station.


N
CONNECTICUT
RIVER
LIMIT OF RECREATION AREA
F (RA)
URL
AP (RA)
AI
AP
OL
UC
UI
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W
F
M
KEY
URBAN
UC - COMMERCIAL
UI - INDUSTRIAL
URL - LIGHT RESIDENTIAL
RA - RECREATION AREA
M - MINING
AGRICULTURE
AP - PASTURE
AI - INTENSIVE AGRICULTURE OF OPEN LAND
F - FOREST
W - WATER AREAS
OL - OPEN LAND
0
1/2 MILE
SCALE

Figure 3-13. Land Use Within One Mile of the Mt. Tom Generating Station.

costs for community services, and (2) environmentally sensitive areas such as agricultural land and wetlands will be developed.

3.5.1.3 Site Vicinity Land Use

Within a 5-mile radius of the Mt. Tom generating station five communities - Holyoke, Northampton, Easthampton, Hadley, and South Hadley (see Figure 1-1) - are more intensely developed than the remainder of the area (Table 3-18). These communities are more urban (20 percent of the land is urban compared to 12 percent for the region) and less forested (44 percent compared to 68 percent for the region). However, a larger share of land in these communities is agricultural, primarily because of the extensive farming section in Hadley that accounts for 44 percent of the agricultural land in these five communities.

Land use within a one-mile radius is shown in Figure 3-13. In the station's immediate vicinity, the land is not intensively developed. Nearby Mt. Tom Reservation, less than one-half mile southwest of the station, is hilly and forested, with maintained picnic areas and hiking trails. A downhill ski area on Mt. Tom is just south of the reservation, and the Holyoke Country Club is about one-quarter mile south-southwest of the station. There are less than 50 houses within a one-mile radius of the Mt. Tom generating station and there are no schools or hospitals within one mile of the station.

The Mt. Holyoke Range, across the Connecticut River from the station, is forested and hilly and has hiking trails. The summit of Mt. Holyoke, about 1.7 miles northeast of the station, is a part of Skinner State Park. Land north and south of the Holyoke Range is generally flat and extensively used for agriculture, with scattered low-density residential development.

3.5.1.4 Projected Land Use

In 1971, the Holyoke Zoning Commission zoned the Mt. Tom generating station site as General Industry. The zoning ordinance requires a minimum lot size of 10,000 square feet, minimum frontage of 100 feet, and a minimum lot depth of 100 feet for its General Industry zone. In addition, building heights are restricted to 60 feet. Although the station was constructed prior to the 1971 zoning laws, it complies with all but the height requirement. Lands in Holyoke surrounding the station are zoned either Highway Business or Industrial. Most of the remainder of the northern part of Holyoke is zoned for agriculture and single-family residences.

Most of the southeastern portion of Northampton (just north of the station) is zoned Special Conservancy-Flood Plain, which places special restrictions on development. However, some sections near the Oxbow (Figure 1-1) are zoned General Industry, and immediately north is an Urban Residential-B zone, allowing townhouses, one-, two-, and three-family dwellings, and lodging houses.

No additional specific local plans relate to the coal conversion. The state plans to acquire additional land on the upper slopes of the Mt. Holyoke Range for inclusion in a state park (to protect the range's higher elevations from development). However, the portions of the range closest to the station are already in either Skinner State Park or the Mt. Tom Reservation.

No Federal activities currently affect the immediate vicinity of the station.

3.5.2 Transportation

Three carriers provide rail freight service in the Lower Pioneer Valley Region. Consolidated Rail Corporation (CONRAIL) operates an east-west mainline, two southerly routes through Connecticut, and a small railroad yard in West Springfield. The Boston & Maine Railroad (B&M) operates a north-south mainline along the western side of the Connecticut River with spurs to Easthampton, Amherst, and the former Westover Air Force Base in Chicopee. The Central Vermont Railroad runs from Vermont to the Connecticut shore through Amherst and Belchertown (Figure 3-14).

Prior to the reconversion to coal, the Mt. Tom generating station received its fuel via the Boston & Maine Railroad, which operates a north-south mainline adjacent to the station site. Operating at full load on an 18-hour a day basis, the station required at least five 30,000-gallon rail cars of oil per day; deliveries were almost on a daily

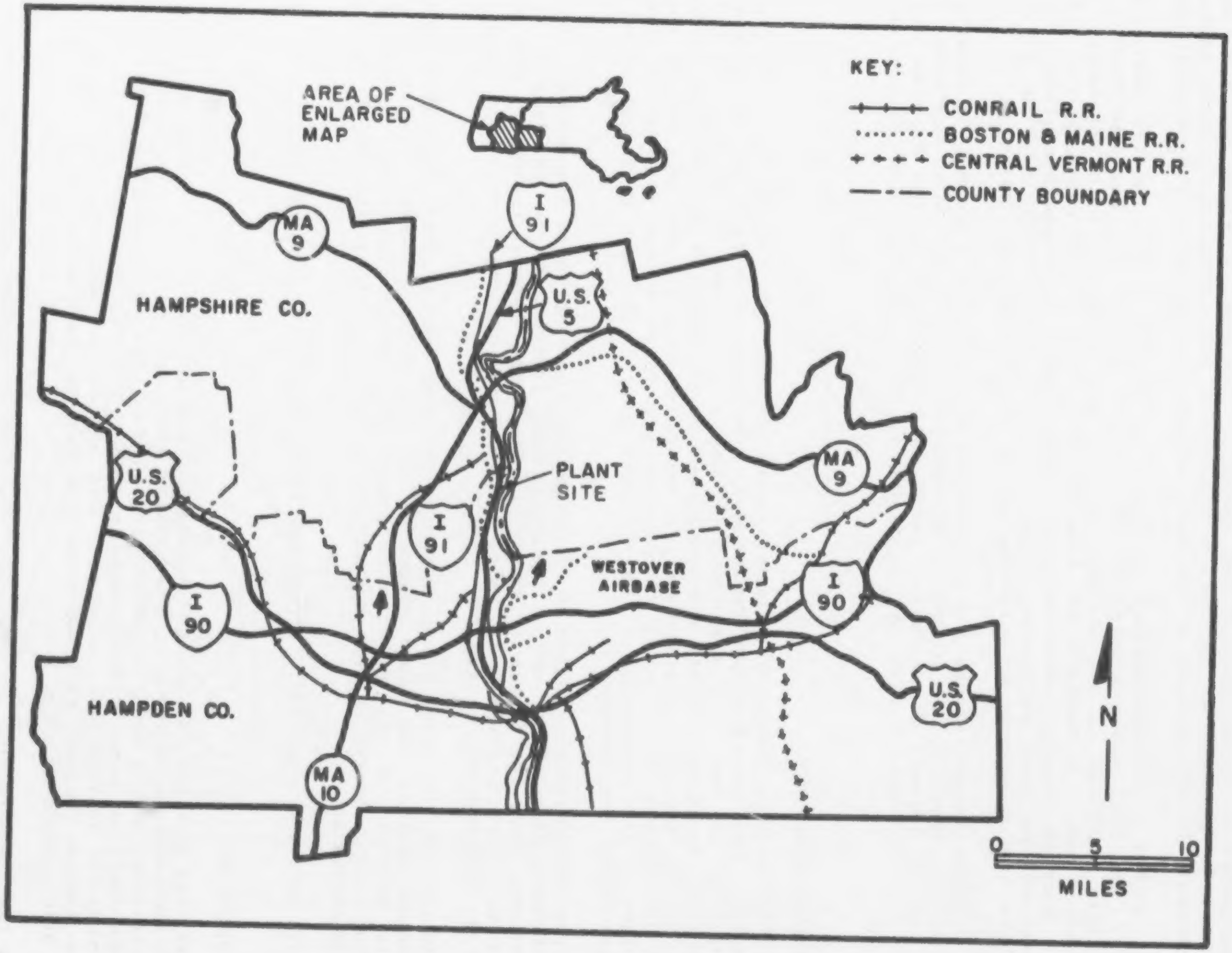
KEY:
CONRAIL R.R.
BOSTON & MAINE R.R.
CENTRAL VERMONT R.R.
COUNTY BOUNDARY
AREA OF ENLARGED MAP
I 91
MA 9
U.S. 5
HAMPSHIRE CO.
U.S. 20
PLANT SITE
MA 9
I 91
WESTOVER AIRBASE
I 90
I 90
HAMPDEN CO.
U.S. 20
N
MA 10
0
5
10
MILES

Figure 3-14. Transportation Network, Lower Pioneer Valley Region.

basis. While operating on coal the station requires a 70-car unit train about every 5 days (Section 2.5.1).

Principal U.S. highways (in addition to Interstates 90 and 91) include Route 5 (the major north-south route prior to construction of I-91) and Route 20 (the major east-west route before construction of the Massachusetts Turnpike). Other principal highways include Massachusetts Route 9, which connects Northampton with Worcester to the east and Pittsfield to the west, and Route 10, which connects Northampton and Westfield to towns in Connecticut.

The Mt. Tom generating station is serviced by U.S Route 5, which runs parallel to I-91. The 1976 traffic counts made by the Massachusetts Department of Public Works indicate an average daily count of 5,350 on Route 5, in the vicinity of the station. (In 1963-1965, prior to completion of I-91, counts of up to 15,000 were recorded.) Generally, two-lane roads averaging daily traffic counts between 12,000 and 15,000 experience traffic congestion during peak hours. Traffic is not a problem in the immediate vicinity of the station.

More than 80 interstate and 18 intrastate motor carriers serve the Lower Pioneer Valley Region. An intermodal terminal in Springfield allows for freight transfer between trucks and trains.

The U.S. Army Corps of Engineers maintains a 15-foot navigation channel on the Connecticut River as far north as Hartford, Connecticut; commercial navigation of the Connecticut River in Massachusetts is not possible because of dams.

3.5.3 Sound Quality

Studies by NUSCO document the pre coal-conversion sound levels at sites near the Mt. Tom generating station that would be sensitive to increases in noise levels caused by the conversion to coal. These noise-sensitive areas identified near the site are: Community of Mt. Tom; Holyoke Country Club; and Thermopyle (see Figure 3-3).

The Environmental Protection Agency utilizes a description of environmental sound known as the day-night sound level, L_{dn}. The day-night sound level is determined from the daytime equivalent sound level and nighttime equivalent sound level. (The equivalent sound level, L_{eq} is the steady sound equal in acoustic energy to the time varying sound during the time period of interest.) Ten dB are added to the nighttime equivalent sound level due to the added sensitivity of residents to nighttime noises.

There are no records of sound level measurements being made at either the community of Mt. Tom or the Holyoke Country Club. Only perfunctory sound level measurements have been made at Thermopyle. In July and August 1979, Northeast Utilities obtained single measurements of ambient sound (NUSCO, 1979). These sound level measurements are summarized below:

A-Weighted Sound Levels Measured At Homes in Thermopyle

Date	Time of Day	A-Weighted Sound Level, dB	Plant
July 24, 1979	10:40 AM	52	Operating
August 16, 1979	11:30 AM	46	Offline

The sound levels prior to coal conversion at the community of Mt. Tom, the Holyoke Country Club, and Thermopyle can be assessed from a knowledge of the character of the land use and nearby roads and highways. Mt. Tom and the country club are adjacent to I-91 and U.S. Route 5. I-91 is a major noise source. Also, the National Academy of Sciences has provided the following guidelines, shown below, which can be used to estimate ambient sounds (National Research Council and others, 1977).

Description	Population Density (people/sq. mi.)	L_{dn} - dB
Rural (undeveloped)	20	35
Rural (partially developed)	60	40
Quiet Suburban	200	45
Normal Suburban	600	50
Urban	2,000	55
Noisy Urban	6,000	60
Very Noisy Urban	20,000	65

Ambient sound levels at the three noise sensitive areas mentioned above can be estimated from the above table, the power plant and the highways' proximity, and the sound level measurements made in 1977 and 1979.

Location	L_{dn} - dB
Community of Mt. Tom	60-65
Holyoke Country Club	55-60
Thermopyle	50-55

EPA indicated that the public welfare is protected at sound levels below L_{dn} = 55 dB. But, they have also noted that in many communities this value is exceeded. The EPA near-term strategy is to reduce community sound levels to below L_{dn} = 65 dB; their long-term goal is to reduce it to below L_{dn} = 55 dB.

The day-night sound level at Thermopyle is presently probably below the EPA criterion for the protection of public welfare from noise. While sounds at the other two noise sensitive areas are above the EPA's long-term goals, they are probably below their near-term goal of L_{dn} = 65 dB, indicating that the sound quality near the Mt. Tom generating station, while not excellent, is satisfactory. Of course, the sound quality at the residential areas nearest to I-91 is probably poor due to excessive traffic noise.

It is possible that the traffic sounds at the community of Mt. Tom and the country club are sufficiently high as to mask any sound presently emitted from the generating station.

3.5.4 Visual Factors

The Mt. Tom generating station is located on the west bank of the Connecticut River. It is surrounded by farmland and forests of the Mt. Tom State Reservation, an area noted for its scenic qualities. The plant can be seen from the local highways (I-91 and U.S. 5) and from the bluffs on either side of the river.

3.5.5 Public Services

The five communities in the vicinity of the Mt. Tom generating station (see Figure 1-1) depend on both ground water wells and surface water reservoirs (Table 3-19). Hadley and Easthampton are serviced exclusively by wells. Northampton, South Hadley, and Holyoke use both reservoir and well water. The Whiting Street Reservoir, serving Holyoke, is the fresh water supply nearest to the Mt. Tom generating station. Most towns chlorinate their water prior to distribution. The city of Holyoke provides water mains for the Mt. Tom generating station and environs.

These five communities dispose of their solid wastes by landfill methods. The Holyoke landfill, located in Granby, has an estimated 10-year available capacity. The South Hadley landfill, located near the Chicopee boundary, is nearly at capacity, and adjacent land has been purchased for future use. In Northampton, voluntary recycling has prolonged the life of the existing landfill, a former gravel pit in the southwest corner of town. The Easthampton site, in the town's northwest corner, has an estimated 3- to 4-year capacity remaining; the Hadley site, off Cemetery Road, has a projected 1- to 2-year capacity.

TABLE 3-19

UTILITY SERVICES IN THE CITIES AND TOWNS IN THE VICINITY OF THE MT. TOM GENERATING STATION

City/Town	Fresh Water Supply	Percent Population w/Sewers	Treatment Plant Volume (MGD)	Treatment Plant Capacity (MGD)	Level of Waste Treatment	Remaining Landfill Capacity in Years
Holyoke	Reservoirs Wells	90	8 (to be built in 1981)	11.5 17.5	Primary Secondary	10
Hadley	Wells	20	0.3	0.11	Secondary	1-2 obtaining new land
South Hadley	Reservoirs Wells	95	58	1.45	Primary Secondary	none new site available
Northampton	Reservoirs Wells	70-75	1.73 (to be built in 1981)	3.4	Primary	20-25
Easthampton	Wells	75	1.5	2.15	Secondary	3-4

Source: Massachusetts Division of Water Resources and communication with Town Service Departments.

3.5.6 Historic, Cultural, and Archaeological Resources

Sites listed in the National Register of Historic Places within a 5-mile radius of the station include: the Hadley Falls Company Housing District in Holyoke; Wisteariahurst in Holyoke, a private home converted into a museum; and the Porter-Phelps-Huntington House in Hadley, an eighteenth century private home.

The Massachusetts Historical Commission lists many additional structures of historical significance in each of the neighboring communities (Lower Pioneer Valley Regional Commission, 1974). Each town has numerous homes and churches of historical significance, although none predates 1700. Historical sites closest to the generating station include the dinosaur tracks (on the river bank near Route 5), two houses southwest of I-91, one house on Russell Cove, and South Hadley's central business district which is 2.5 miles from the station and includes most of the South Hadley historical sites.

In July 1981, a review of the Mt. Tom generating station area by the Massachusetts Historical Commission staff led to a reappraisal of archaeological resources at the site (NUSCO, 1981d). Two previously recorded archaeological sites within site boundaries on the floodplain south of Kennedy Brook close to the river were identified. These sites are a prehistoric occupation site (not a campsite) south of the brook dating to the Woodland Period, which began about 3,000 years ago. This site appeared to be not far from the fly ash basin, the grub storage area and the borrow pit identified by the utility for development. As indicated by the utility in the final environmental impact report to the state (NUSCO, 1981d) the restoration of the south fly ash basin had been largely completed and the grub storage area established by the time the new information became available. Excavation of the borrow pit, then underway, has since been confined to extraction of previous deposits of fly ash pending further clarification of resources at the site.

To guide future activities at the site, the utility contracted a consultant to make a preliminary review of the area. A report on that preliminary investigation was included with the final state EIR (NUSCO, 1981d). The report confirmed the presence of the two prehistoric sites and indicated that one site is in the undisturbed area south of Kennedy Brook. The report also indicated that there could be some archaeological interest in the knolls or ridges at the edge of the cornfield that is between Route 5 and the riverbank, judging from experience elsewhere. Consultations between the utility and the State Archaeologist have been undertaken to review this report, and further archaeological investigations will proceed to the extent necessary to guide future activities (NUSCO, 1981d).

3.5.7 Socioeconomics

The conversion of Mt. Tom to an alternate fuel requires the addition of approximately 18 people to the labor force at the station. During the construction period the increase in labor force was also small. The utility has indicated an increase of 40 additional temporary parking places (NUSCO, 1981d), suggesting that no more than 50 to 60 temporary construction workers were employed at any one time. An employment change of this magnitude is not expected to cause a significant impact on the socioeconomic structure in the site vicinity. For this reason a discussion of baseline socioeconomics is not considered relevant.

4.0 ENVIRONMENTAL CONSEQUENCES

This chapter presents a detailed analysis of the environmental consequences of the conversion from oil to low-sulfur coal at the Mt. Tom generating station and a summary of the consequences of reasonable alternatives. As discussed in Chapter 2.0, the low-sulfur coal conversion was the alternative selected by the utility; therefore, this alternative is stressed.

Emphasis is placed here on significant issues; other issues are discussed only briefly in accordance with the CEQ regulations (40 CFR 1500.4(c)). Under the CEQ regulations, issues may be considered significant based on context and intensity (40 CFR 1500.27).

"Context" refers to the framework into which the action is placed - local, national, world. Certain site-specific EISs may consider only the local issues. Since regional issues are discussed in the Northeast Regional EIS (DOE, 1981) and in the Programmatic EIS (DOE, 1979a), only local issues are emphasized in this EIS. A summary of cumulative environmental effects was presented in Section 2.7.

"Intensity" refers to the severity of the impact, and is to be considered based on 10 criteria as follows:

1) Whether the impact is beneficial or adverse;
2) Effect on public health and safety;
3) Unique characteristics of area affected by the proposed action.
4) Degree of controversiality of the proposed action;
5) Degree to which impacts are uncertain or unknown or unknown risks;
6) Precedent setting nature of the action;
7) Cumulative impact when considered with similar actions;
8) Impact of action on sites in National Register of Historic Places, or other scientific, cultural, or historic resources;
9) Impact on endangered or threatened species or critical habitat;
10) Possible conflict with any Federal, state, or local environmental regulations.

Taken in this framework an issue must be considered significant if it is of public concern. The actual impact to the environment, both natural and manmade, may or may not be determined to be severe.

Issues of primary concern identified during the scoping process with regard to this proposed action (issuance of the NOE) and the conversion of the Mt. Tom generating station to burn low-sulfur coal are:

- Air Quality
- Water Quality (surface and ground)
- Noise
- Encroachment on the floodplain.

These issues are discussed in depth, primarily in regard to the low-sulfur coal conversion alternative. It should be noted that any impacts must be viewed from the perspective of the incremental changes resulting from the change in fuel (from oil to low-sulfur coal). These incremental changes are considered for both the period of the DCO and for the remainder of the proposed life of the plant. Impacts to other aspects of the natural and manmade environment are discussed only briefly (see Table 2-2).

Because the Mt. Tom generating station was designed and built to burn coal, only minimal construction activities (Section 4.1) have been required to return the facility to use of coal as the primary energy source. Operational impacts (Section 4.2) will, as noted previously, be incremental over the oil-burning configuration. They involve primarily: (1) a temporary (2 to 2-1/2 years) increase in emissions of total suspended particulates; (2) a possible degradation of ground water quality in the immediate plant vicinity and percolation of this contaminated ground water to the Connecticut River; and (3) some intermittent increase in noise. Finally, because about 77 acres of the total 89-acre site are within the 100-year floodplain, use of onsite land for ash storage and other development must be carefully considered.

4.1 CONSTRUCTION IMPACTS

4.1.1 Low-sulfur Coal Conversion

Because the station was originally constructed to burn coal, the conversion required primarily replacement or upgrading of equipment either to meet present regulatory standards or to improve efficiency. Because of the nature of the conversion and because all activities are closely regulated by permits (see Section 1.6), the construction impacts should not have any long-term impacts.

4.1.1.1 Phase I - Initial Construction

The plant began operating with coal shortly after the DCO was received (Phase I). Actual construction began in June 1981, and reconversion to coal, in early December 1981. The DCO was issued November 24, 1981. During the initial construction period essential construction included:

- Repair and upgrading of the rail yards and yard engine.
- Overhaul and modifications to the thawer and shaker facilities, and to the existing precipitator (this has continued into Phase II).
- Replacement and repair of coal handling equipment, conveyors, crusher, pulverizers, etc.
- Initial work for coal, ash, and wastewater storage.

During this Phase I construction, the plant was off line for varying periods to complete certain construction activities.

4.1.1.2 Phase II - Coal Burning Under DCO

During the period of coal burning under the DCO (December 1981 to February 1984), work will continue on securing the new precipitator so that it can be installed during the last 30 to 60 days of Phase II. The new precipitator will be installed during a plant shutdown before the DCO expires.

Additional onsite construction will be required to install the dry ash retrieval system for fly ash.

Also during this period, the initial water quality monitoring program is to be completed and, should significant impacts be found, mitigative measures must be taken as required by various permits. Note that the utility has agreed to a long-term monitoring program in addition to that required initially by the MOU.

4.1.1.3 Phase III - Post DCO Coal Burning

Construction activities during the DCO period (and also at intervals throughout the life of the plant) would be required to develop landfill sites for bottom ash. This may necessitate building roads onsite, erecting dikes, and other dust-creating activities.

4.1.1.4 Summary

Because of the nature of the construction activities and because of the extent of permitting requirements to carry on the construction activity, the construction impacts can be considered short term, lasting only for the duration of the particular construction phase. Impacts to ground water or surface water quality resulting from storage of ash and coal or those resulting from changing land use are considered operational impacts and are discussed in Section 4.2 of this EIS.

4.1.2 Alternatives

4.1.2.1 High-sulfur Coal

Should a high-sulfur coal be used, scrubbers would have to be installed. This would increase the amount of construction onsite for limestone and sludge storage, for additional facilities, and for an additional thawer/shaker facility.

4.1.2.2 Offsite Ash Disposal

If new sites are required offsite for waste disposal, the type of impacts would be similar to those for onsite storage, but additional transportation would be required. If private, existing sites were available, or if a market is secured for fly ash, construction impacts would be reduced.

4.2 OPERATIONAL IMPACTS

4.2.1 Geology

No impacts to the geology of the site are expected as a result of operation of the Mt. Tom generating station on any alternate fuel. Impacts to the soils onsite would occur throughout the operation of the facility, but would result from the construction of ponds for disposal of ash and wastewater as noted in Section 4.1.

4.2.2 Water Resources

4.2.2.1 Surface Water

Water Quantity

It is anticipated that the Mt. Tom conversion will not have a measurable impact on surface water quantity. The plant withdraws more than 133 MGD for once-through cooling and other uses. An increase of about 1.2 MGD is required initially for sluicing under the low-sulfur coal alternative.

By creating new ponds on formerly open land, surface runoff is reduced. However, the areas involved are very small (less than 50 acres), and currently contribute insignificant amounts of runoff to Kennedy Brook and the Connecticut River. Evaporation and infiltration from the disposal ponds will reduce the amount of surface water returned to the river. Again, the amounts are small in comparison to flows in the Connecticut River. Total flows to the ash ponds are on the order of 1.2 MGD, or 1.9 cfs (see Section 2.3.1.4). Even assuming a "worst-case" condition, that is, 100 percent evaporation/ infiltration of all sluicing water, the mean summer flow of the Connecticut River (5,000 cfs) would be reduced by four-hundredths of one percent, far below the accuracy to which flows can be measured. By March 1983, the utility expects to have a dry fly ash disposal system in use, and the sluicing water flow will be reduced to 375,000 gpd.

Water Quality

As discussed in Section 2.3.1.4, changes in plant discharges have required a revised NPDES permit. The discharges are required to meet the limitations listed in Section 2.3.1.1. They are also subject to periodic chemical analyses for various pollutants. These analyses are usually a part of the data submitted with the permit application. In this case, sampling and analysis could not be made until after conversion to coal had begun. Therefore, a schedule of compliance sampling and analysis has been made a condition of the NPDES permit.

The expected flow rates for sluicing waters are 375,000 gpd to the bottom ash pond, and an average of 875,000 gpd to the fly ash pond. These ponds are presently unlined. Based on flow net analyses and other tests performed by Gibbs & Hill (1981) it is expected that all bottom ash waters will percolate into the surface materials and into the underlying northern aquifer (see Sections 3.2.2 and 4.2.2.2). Some 100,000 gpd from the fly ash pond may infiltrate into the southern aquifer during the initial period of coal burning while the fly ash is being sluiced to the pond. Coal runoff will be contained in a lined pond and any overflow will be directed through the plant wastewater system. According to U.S. Weather Bureau figures, precipitation in the area exceeds rainfall by 17 inches (Michael Baker, Jr, 1979). This would not be a measurable dilution effect. It can be assumed that, based on the above figures, nearly 800,000 gpd of fly ash pond discharge would have to be treated for release to the Connecticut River. HWP is expected to terminate the wet sluicing of fly ash in March 1983. After that time, the worst case condition would be that the entire 375,000 gpd of bottom ash sluice water enter the river.

Table 4-1 provides information on ash pond discharges as compiled by GAI (1979). Note that only a few data points were available and that there is a wide range of values for the parameters.

To examine possible impacts, the effects of direct discharge of untreated ash pond waters into the Connecticut River have been investigated. Table 4-2 provides an analysis of the increase in concentrations of selected parameters which could be expected as a result of discharge of the average daily overflow from the fly ash pond (about 800,000 gpd) and assumes that this is not treated. This analysis was based on average concentrations given in Table 4-1 and on an average river flow of 5,000 cfs. Note that ambient concentration of iron is above EPA drinking water standards; this is not a health standard but is a taste standard. Also the calculations were based on only three data points (see Table 4-1). Ambient manganese levels are above drinking water standards but the effects of the increase from the ash discharge would not be significant. Proper treatment of the water as required by the NPDES permit will reduce the concentrations of pollutants in the discharge.

Floodplain Assessment and Preliminary Determinations

In May 1977, the President issued two executive orders: EO 11988 - Floodplain Management, and EO 11990 - Protection of Wetlands. These were parallel documents charging each Federal agency with a set of responsibilities aimed at avoiding, to the extent possible, any additional short-term or long-term impacts on the floodplains and wetlands of the United States. DOE responded to these executive orders with the regulations promulgated in 10 CFR 1022. These regulations specify in (10 CFR 1022.3) that:

"...DOE shall exercise leadership and take action to...incorporate floodplain management goals...into its planning, regulatory, and decision-making processes and shall to the extent practicable reduce the hazard and risk of flood loss; minimize the impact of floods on human safety, health and welfare; and restore and preserve natural and beneficial values served by floodplains..." [10 CFR 1022.3]. Pursuant to these requirements, DOE has assessed the floodplain impacts of the proposed action and performed a preliminary determination of the practicability of alternatives to locating this action in a floodplain. Before DOE makes a decision concerning this proposed action, a final determination will be published.

Concerns over use of the 100-year floodplain of the Connecticut River for ash and coal storage and for other additional development have also been noted by DEQE. In the Final EIR to the state, the utility has attempted to respond to these concerns (NUSCO, 1981d). An analysis of HEC-2 models by the utility indicates that no measurable increase in flood levels will occur as a result of the planned construction (see Table 3-3). NUSCO (1981d) indicates the combined effect of all construction presently contemplated on the 100-year floodplain would displace 103 acre-feet of flood storage. If sale of fly ash is not feasible or if environmentally acceptable disposal sites cannot be found within a cost effective distance from the plant, the study indicates that use of the site for ash storage over a 20-year period would displace an additional 44 acre-feet of flood storage. The total displaced flood storage value is on the order of 1/10,000 of the volume of water that would flow past the site during a 100-year flood event.

TABLE 4-1

ANALYSES OF ASH POND DISCHARGES
(in mg/liter)

Substance	Fly Ash Pond Range	Fly Ash Pond Avg.	Fly Ash Pond Data Pts.
Arsenic	0.01 - 1.1	0.38	3
Barium	0.2 - 0.3	0.25	2
Cadmium	0.001 - 0.037	0.019	2
Chloride	6 - 7	6.5	2
Chromium	0.02 - 0.067	0.044	2
Copper	0.02 - 2.4	0.91	3
Cyanide	-	-	-
Iron	1.44 - 630	211.12	3
Lead	0.01 - 0.91	0.33	3
Manganese	0.13 - 0.48	0.31	2
Selenium	0.002 - 0.33	0.12	3
Silver	-	-	-
Sulfate	209 - 358	283.5	2
Zinc	0.06 - 2.2	1.26	3

Substance	Bottom Ash Pond Range	Bottom Ash Pond Avg.	Bottom Ash Pond Data Pts.
Arsenic	0.006 - 0.018	0.012	2
Barium	0.1 - 0.2	0.15	2
Cadmium	0.001 - 0.003	0.002	2
Chloride	7 - 8	7.5	2
Chromium	0.009 - 0.01	0.0095	2
Copper	0.041 - 0.065	0.053	2
Cyanide	-	-	-
Iron	5.29 - 5.98	5.64	2
Lead	0.02 - 0.02	0.02	2
Manganese	0.16 - 0.58	0.37	2
Selenium	0.002 - 0.011	0.007	2
Silver	-	-	-
Sulfate	49 - 139	94	2
Zinc	0.09 - 0.14	0.12	2

Source: GAI, 1979.

TABLE 4-2

AVERAGE POLLUTANT CONCENTRATIONS CONNECTICUT RIVER[a]

Parameter	Fly Ash Discharge (mg/liter)	Increase Due to Discharge (μg/liter)	Ambient Level (μg/liter)	EPA Drinking Water Standards (μg/liter)
Arsenic	.38	0.10	0.43	50
Barium	.25	0.06	27.7	1,000
Cadmium	0.019	0.005	1.0	10
Chlorine	6.5	1.6	-	250,000
Chromium	0.044	0.011	12.0	50
Copper	0.91	0.23	4.4	1,000
Iron	211	53	610	300
Lead	0.33	0.083	12	50
Manganese	0.31	0.078	68.8	50
Selenium	0.12	0.030	0.00	10
Zinc	1.26	0.032	14.1	5,000

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[a] Based on average discharge levels of components in Table 4-1. Uses fly ash discharge of 800,000 cfs. No bottom ash discharge. River flow at 5,000 cfs.

As noted in Section 2.5.3, the utility is actively pursuing sale of fly ash to reduce potential impacts to the floodplain. Plans for sale of the ash cannot be completed until the characteristics of the ash have been determined after a period of analysis to determine content and range of variation of characteristics following the reconversion to coal burning. The utility (NUSCO, 1981d) has been permitted to use the fly ash basin until March 1983; the dike elevation of 122.5 feet will protect it from the 100-year flood during this period.

Another alternative is to obtain offsite storage of the ash at a presently active site or at a newly acquired site. Impacts of such disposal are considered in Section 4.2.5.

As a mitigative measure the utility has set aside 300 acre-feet of compensatory storage at the Northfield Mountain Pumped Storage Facility on the Connecticut River, some 30 river miles upstream. Analysis of flood conditions indicates that addition of this upstream storage volume would effectively eliminate an increase in downstream flooding caused by ash disposal facilities.

Most of the facilities in the 100-year floodplain were originally constructed during the initial period of coal firing - the powerhouse, the switchyard, the railyards, and the coal handling equipment, for example. Because of the locations of these facilities and the limited space available on the property outside the 100-year floodplain (see Figure 3-5), there appear to be no reasonable alternatives to the location of the coal storage and runoff areas or the wastewater or bottom ash storage ponds. There also appears to be no feasible onsite alternative to storage of fly ash in the reactivated basin, until analyses of the actual ash produced during coal firing provide information regarding characteristics which might make it marketable. The utility will attempt to secure offsite disposal if no market is found.

4.2.2.2 Ground Water

The major issues of environmental concern with regard to the ground water resources of the Mt. Tom generating station relate to the water quality of the ground water and of its discharge to the Connecticut River. To address these concerns, the utility has undertaken a major hydrogeologic study (Gibbs & Hill, 1981) and is currently conducting monthly post-conversion monitoring of water quality in 11 onsite wells, as required by the Subsurface Discharge Permit issued by DEQE (see Table 1-3).

The elements of concern at the site are the coal pile storage area and its leachate/runoff basin, the normal wasewater' basin, the special wastewater basin, the bottom ash basins, and the fly ash basin (see Figure 2-1). The coal pile and its leachate/runoff collection basin are lined. This is because a plume of contaminated water was found to extend from the old coal pile area to the river (Gibbs & Hill, 1981). The utility is treating all discharge from this basin. Assuming the integrity of the liner is maintained, there should be no potential for a release of contamination from this area; therefore, there should be no impact on the ground water quality at the site from the coal pile. The only impact that could result would be a slight decrease in the natural infiltration (recharge) immediately under the coal pile and its basin due to the existence of the impermeable liner. The effects of this on the northern aquifer system should be negligible.

The five other basins operating onsite are unlined and rely, to varying degrees, on the infiltration of liquid as a means of controlling the head in the basins, thereby minimizing the need for direct overflow discharge to the river. The major environmental concern is whether this planned infiltration is degrading the ground water quality of the area.

Water Levels

As discussed in Section 3.2.2, ground water flow is restricted almost exclusively to the site area. There probably is no mixing of shallow ground water between the northern and southern aquifers. All basins except the fly ash basin are located within the northern aquifer system. The two bottom ash basins and the two wastewater basins have been excavated to approximately 108 feet MSL, about 8 feet above the natural water table under average flow conditions in the river. The bottom of the fly ash basin in the southern aquifer is at Elevation 107 feet MSL, approximately 875,000 gallons per day (gpd) is slurried into the fly ash setting basin and 375,000 gpd into the bottom ash basin. Since plant personnel report that the heads in the basins remain fairly constant during the plant operation and drop appreciably during the plant shut-down, it can be assumed that much of the water from the basins is infiltrating into the subsurface. Post-conversion water levels are not currently available to confirm whether a mounding of the ground water beneath the basins has taken place. However, with velocities of approximately 4.9 feet/month in the northern aquifer and 0.5 feet/month in the southern aquifer (Gibbs & Hill, 1981) it is likely that some mounding has ocurred, resulting in a higher water table around the ponds.

Potential Contaminant Migration

The potential for ground water contamination from ash depends on several factors:

- The concentration of leachable contaminants in the ash,
- Their degree of leachability,
- And the dilution or attenuation effects at work in the subsurface.

Most of the elements listed above are contained in the ash as trace elements, not as major constituents of the material. Bottom ash generally contains varying quantities of silica, aluminum, and metal oxides (such as iron, calcium, magnesium, sodium, and potassium). In fly ash, the principal ions in solution are calcium and sulfate, with smaller quantities of magnesium, sodium, potassium, and silicate ions (NUSCO, 1982a). Estimated concentrations of trace metals which may be expected in leachates from fly ash and bottom ash from the unlined basins at Mt. Tom are given in Tables 4-4 and 4-5 (Table 4-3 provides similar data for coal lechate). All of these projected values and those of the plant wastewater meet applicable primary and secondary EPA drinking water standards for leachate based on a non-hazardous RCRA criteria of 100 times the standards. The water in all basins also meets the standards for quality allowed to be discharged to the river under HWP's permit. For these reasons, the infiltration of liquid from the basins does not, alone, constitute a contamination of the ground water.

Several other factors are also at work in the subsurface to reduce the potential for contamination. Heavy metals often precipitate out of solution and become immobilized by reactions with ions occurring naturally in the ground water. These include the heavy metals arsenic, cadmium, copper, iron, mercury, molybdenum, silver, and zinc. Adsorption adherence to soil particles, is also a significant mechanism in reducing the concentration of contaminants in the leachate. Leachate retention tests were performed to determine gross attentuation of leachate constituents, by the soil, incorporating such mechanisms as adsorption, fixation, biological activity, and mechanical filtration, among others. It was found that cation exchange was responsible for selected chemical uptake of certain contaminants, particularly sodium, calcium, and iron (Gibbs & Hill, 1981).

Ground water dispersion is the reduction of contaminant concentrations due to mechanical mixing as the ground water flows through a porous material. The greater the amount of layering and diversity in soil particle size, the greater the dispersion. The Gibbs & Hill study (1981) shows that the ash leachate with respect to copper, for example, is subject to reduction by a factor of 1000 after ground water dispersion. This means that stabilization in the subsurface reduces the concentrations in the leachate leaving the basins.

To further determine the effects of leachate on water quality, flow net analyses were calculated for both the northern and southern aquifers. The analyses give an indication of the importance of dilution in reducing leachate concentrations. It was determined that the flow rate for the northern aquifer would be 62 cubic feet per day per foot of shoreline (cft/day/ft), or 3.8 cfs for the aquifer (assuming the water table was at 110 feet MSL). For the southern aquifer under similar conditions the flow would be 17 cft/day/ft, or a total of 0.6 cfs.

Using these figures, mixing ratios can be calculated for the contribution of ground water to river flow at various river flows. For example, for the fly ash pond, the average ground water flow to the river would be 0.167 cfs. At an average river flow of 5,000 cfs, this would be a ratio of about 1 to 30,000. For the bottom ash pond, the average ground water flow would be 0.538 cfs, or a ratio of 1 to about 10,000.

Analyses using these results in conjunction with soil retention determinations are presented in Tables 4-3 through 4-5. For the typical coal, cadmium, iron, and manganese are above drinking water standards (Table 4-3). For bottom ash, mercury would be above drinking water standards (Table 4-4) and for fly ash, iron, and manganese, exceed

TABLE 4-3

SUMMARY - WATER QUALITY - NORTHERN AQUIFER - COAL LEACHATE

Parameter	1. Drinking Water Standard (mg/1)	2. Average Groundwater Quality (mg/1)	3. Average Conn. River Water Quality (mg/1)	4. Average Leachate Concen. (mg/1)	5. *Leachate Concen. at River Boundary after GW Dispersion (mg/1)	6. **Maximum Conn. River Concen. after Leachate Mixing (mg/1)	7. Ave. Leachate Concen. after Soil Passage (mg/1)	8. *Leachate Concen. at River Boundary after GW Dispersion and Soil Passage (mg/1)	9. **Maximum Conn. River Concen. after Leachate Mixing (mg/1)
Aluminum	-	4.83	.1	0.1	.0001	.0000001	0.265	.000265	.0000004
Antimony	-	0.1	.1	0.1	.0001	.0000001	0.1	.0001	.0000001
Arsenic	0.05	.0169	.0027	.002	.000002	.0000000028	.00875	.0000088	.000000012
Barium	1.0	.031	.1	0.1	.0001	.0000001	.1375	.0001375	.0000002
Beryllium	-	.005	.005	.005	.000005	.000000007	.005	.000005	.000000007
Boron	-	.538	1.25	2.4	.0024	.0000034	2.75	.00275	.0000039
Cadmium	0.01	.0121	.0016	48.15	.04815	.000068	.00675	.0000068	.0000000096
Calcium	-	53.03	9.66	48.2	.0482	.0000681	34.53	.03453	.0000498
Chromium	0.05	.02	.03	.02	.00002	.000000028	.02	.00002	.000000028
Cobalt	-	.158	.05	0.07	.00007	.000000098	.075	.000075	.0000001
Copper	1.0	.0319	.021	0.27	.00027	.0000004	.47	.00047	.0000007
Iron	0.3	24.73	.233	0.64	.00064	.0000009	.0975	.0000975	.0000001
Lead	.05	.031	.025	.025	.000025	.000000035	.025	.000025	.000000035
Magnesium	-	11.55	1.74	2.28	.00228	.0000032	6.35	.00635	.000009
Manganese	0.05	8.52	.052	0.25	.00025	.0000004	.8175	.0008175	.0000012
Mercury	0.002	.00026	.00025	0.001 2	.0000012	.0000000016	.0003	.0000003	.00000000042
Molybdenum	-	0.1	.01	0.1	.0001	.0000001	0.1	.0001	.0000001
Nickel	-	0.18	.025	1.61	.00161	.0000023	0.83	.00083	.0000012
Selenium	0.01	.0037	.002	0.002	.000002	.0000000028	.002	.000002	.0000000028
Silver	0.05	.01	.01	0.01	.00001	.000000014	.01	.00001	.0000000141
Strontium	-	.294	6.96	0.2	.0002	.0000003	0.415	.000415	.0000006
Sodium	-	28.31	6.96	7.76	.00776	.000011	16.71	.01371	.0000194
Vanadium	-	0.2	.2	0.2	.0002	.0000015	0.2	.0002	.0000003
Zinc	5.0	.200	.042	0.05	.00005	.0000003	12.13	.01213	.0000171

* Concentration entering river at the end of 10,000 days: Values are based on 2-D Mass Transport Model, by Dr. Robert Cleary of Princeton University.

** Concentration above ambient concentrations.

Source: Gibbs & Hill, 1981.

Note: Leachate tests run on fresh coal similar to that expected to be used at Mt. Tom generating station.

TABLE 4-4

SUMMARY - WATER QUALITY - NORTHERN AQUIFER - BOTTOM ASH LEACHATE

Parameter	1. Drinking Water Standard (mg/l)	2. Average Groundwater Quality (mg/l)	3. Average Conn. River Water Quality (mg/l)	4. Average Leachate Concen. (mg/l)	5. *Leachate Concen. at River Boundary after GW Dispersion (mg/l)	6. **Maximum Conn. River Concen. after Leachate Mixing (mg/l)	7. Ave. Leachate Concen. after Soil Passage (mg/l)	8. *Leachate Concen. at River Boundary after GW Dispersion and Soil Passage (mg/l)	9. **Maximum Conn. River Concen. after Leachate Mixing (mg/l)
Aluminum	-	4.83	.1	.1	.0001	.0000001	.125	.000125	.0000001
Antimony	-	0.1	.1	.1	.0001	.0000001	.1	.0001	.0000001
Arsenic	0.05	.0169	.0027	.0425	.0000425	.000000045	.03	.00003	.000000032
Barium	1.0	.031	.1	.1	.0001	.0000001	.01	.00001	.00000001
Beryllium	-	.005	.005	.005	.000005	.0000000053	.005	.000005	.0000000053
Boron	-	.538	1.25	1.15	.00115	.0000012	1.15	.00115	.0000012
Cadmium	0.01	.0121	.0016	.0039	.0000039	.0000000041	.0023	.0000023	.0000000024
Calcium	-	53.03	9.66	24.9	.0249	.0000264	27.1	.0271	.0000287
Chromium	0.05	.02	.03	.02	.00002	.000000021	.02	.00002	.000000021
Cobalt	-	.158	.05	.06	.00006	.000000064	.4	.0004	.0000004
Copper	1.0	.0319	.021	.055	.000055	.000000058	.015	.000015	.000000016
Iron	0.3	24.73	.233	.03	.00003	.000000032	.035	.000035	.000000037
Lead	.05	.031	.025	.025	.000025	.000000026	.025	.000025	.000000026
Magnesium	-	11.55	1.74	.445	.000445	.0000005	1.44	.00144	.0000015
Manganese	0.05	8.52	.052	.025	.000025	.000000026	.17	.00017	.0000002
Mercury	0.002	.00026	.00025	.01	.00001	.00000001	.00025	.0000003	.00000000032
Molybdenum	-	.1	.01	.3	.0003	.0000003	.1	.0001	.0000001
Nickel	-	.18	.025	.55	.00055	.0000006	.035	.000035	.000000037
Selenium	0.01	.0037	.002	.002	.000002	.0000000021	.014	.000014	.000000015
Silver	0.05	.01	.1	.01	.00001	.00000001	.01	.00001	.00000001
Strontium	-	.294	.01	.15	.00015	.0000002	.875	.000875	.0000009
Sodium	-	28.31	6.96	.375	.000375	.0000004	4.025	.004025	.0000043
Vanadium	-	.2	.2	.2	.0002	.0000002	.2	.0002	.0000002
Zinc	5.0	.200	.042	.08	.00008	.000000084	.0175	.0000175	.000000018

* Concentration entering river at the end of 1,000 days: Values are based on 2-D Mass Transport Model, by Dr. Robert Cleary of Princeton University.

** Concentration above ambient concentrations.

Source: Gibbs & Hill, 1981.

Note: Leachate tests run on fresh bottom ash similar to that expected at Mt. Tom generating station.

TABLE 4-5

SUMMARY - WATER QUALITY - SOUTHERN AQUIFER - FLY ASH LEACHATE

Parameter	1. Drinking Water Standard (mg/1)	2. Average Groundwater Quality (mg/1)	3. Average Conn. River Water Quality (mg/1)	4. Average Leachate Concen. (mg/1)	5. *Leachate Concen. at River Boundary after GW Dispersion (mg/1)	6. **Maximum Conn. River Concen. after Leachate Mixing (mg/1)	7. Ave. Leachate Concen. after Soil Passage (mg/1)	8. *Leachate Concen. at River Boundary after GW Dispersion and Soil Passage (mg/1)	9. **Maximum Conn. River Concen. after Leachate Mixing (mg/1)
Aluminum	-	3.24	.1	1.38	.00138	.0000005	.265	.000265	.000000087
Antimony	-	0.1	.1	.1	.0001	.000000033	.1	.0001	.000000033
Arsenic	0.05	.0124	.0027	.725	.000725	.0000002	.174	.000174	.000000057
Barium	1.0	.119	.1	.1	.0001	.000000033	.16	.00016	.000000056
Beryllium	-	.005	.005	.005	.000005	.00000000164	.005	.000005	.0000000016
Boron	-	.5	1.25	1.15	.00115	.0000004	.97	.00097	.0000003
Cadmium	0.01	.008	.0016	.015	.000015	.0000000049	.0065	.0000065	.0000000021
Calcium	-	58.76	9.66	167.50	.1675	.0000549	136.69	.13669	.000045
Chromium	0.05	.014	.03	.02	.00002	.0000000066	.02	.00002	.0000000066
Cobalt	-	.05	.05	.05	.00005	.000000016	.075	.000075	.000000025
Copper	1.0	.076	.021	.125	.000125	.000000041	.086	.000086	.000000028
Iron	0.3	10.41	.233	.03	.00003	.0000000099	.1	.0001	.000000033
Lead	0.05	.0369	.025	.025	.000025	.0000000082	.032	.000032	.00000001
Magnesium	-	11.67	1.74	5.275	.005275	.0000017	13.24	.01324	.0000044
Manganese	0.05	2.03	.052	.175	.0000175	.0000000057	.379	.000379	.0000001
Mercury	0.002	.00027	.00025	.00087	.0000009	.00000000029	.0014	.0000014	.00000000046
Molybdenum	-	.1	.01	.625	.000625	.0000002	.185	.000185	.00000006
Nickel	-	.172	.025	.085	.000085	.000000028	.128	.000128	.000000042
Selenium	0.01	.0076	.002	.23	.00023	.000000076	.065	.000065	.000000021
Silver	0.05	.01	.1	.01	.00001	.0000000033	.01	.00001	.0000000033
Strontium	-	.390	.01	1.625	.001625	.0000005	1.27	.00127	.0000004
Sodium	-	22.797	6.96	4.25	.00425	.0000014	7.84	.00784	.0000026
Vanadium	-	.2	.2	.48	.00048	.0000002	.2	.0002	.000000066
Zinc	5.0	.095	.042	.25	.00025	.000000082	.461	.000461	.0000002

* Concentration entering river at the end of 10,000 days: Values are based on 2-D Mass Transport Model, by Dr. Robert Cleary of Princeton University.

** Concentration above ambient concentrations.

Source: Gibbs & Hill, 1981.

Note: Leachate tests run on fresh fly ash similar to that expected at Mt. Tom generating station.

standards (Table 4-5). Analyses of soil retention capabilities indicate that all of these concentrations would be diluted to well below standards by dispersion and soil retention.

Results of both computer model studies and sample analyses indicate that impacts from leachates would be restricted to onsite ground water supplies and that there will be no measurable changes to water quality in the Connecticut River.

Ground Water Monitoring

More than 20 wells have been drilled at the Mt. Tom generating station for the purpose of monitoring water quality. A number of these wells were monitored prior to conversion during the Gibbs & Hill hydrogeologic study in order to establish a preconversion water quality baseline. Since conversion in December 1981, monthly monitoring in 11 wells has been conducted. The current monitoring well locations are shown in Figure 4-1. Water quality analyses for selected parameters have been analyzed for the period January 19, 1981 through February 25, 1982 (NUSCO, 1982c). The analytical results are in a data management system that not only lists the results, but graphically plots the results of a downgradient well compared with the appropriate upgradient well. In general, since the date of conversion, the following observations can be made:

- Downgradient Well OW-5 generally exhibits higher concentrations than its upgradient Well OW-6; downgradient Well OW-18 exhibits higher concentrations than background Well OW-19; the remaining wells exhibit essentially a similar range of concentrations.

- Changes in concentration since conversion generally entail a slight increase in Cd (Wells 5A, 6, 9, 10, 23, 19), Pb (Wells 6, 9, 19), and Ni (Wells 5A, 9, 10, 23, 19, 18) and a sharp increase in Hg in Well OW-5A and Ni in OW-6.

A difference in overall water quality could not be associated with depth, since Well 9 has better quality than Well 9A (immediately adjacent) and is also deeper, while 5A has better quality than Well 5, yet is shallower.

The concentrations obtained from the analyses do not lead to the conclusion that a change in ground water quality has taken place. Based on the calculated velocities from the hydrogeologic study and the location of the monitoring wells, water infiltrating into the area beneath the ponds may not have had time to reach the monitoring wells, as of the February sampling date. Therefore, a question remains as to whether these changes in water quality since conversion to coal are indicative of the influence of infiltrating water from the various basins. Continued monthly monitoring is necessary to detect changes in water quality resulting from the conversion.

Summary

Several concerns about possible ground water contamination resulting from the conversion cannot be resolved at this time. Among these concerns are the following:

- Has the ground water experienced significant degradation since conversion to coal?

- Are the pre- and post-conversion ground water quality results measuring the same parameters and are they comparable?

- Is more extensive testing necessary?

- Should the basins be lined?

Analysis of several more months of data will be required before trends can be identified or direct casual relationships established between ground water quality and the effects of infiltration of metals from the ash ponds. Pre-conversion monitoring was conducted for dissolved parameters, while initial post-conversion analyses determined total concentrations. Total and dissolved results often show significant differences in concentrations of the same parameter. Standardized testing and sampling procedures were begun in February 1982, so that all subsequent results should allow comparison with pre-conversion data.

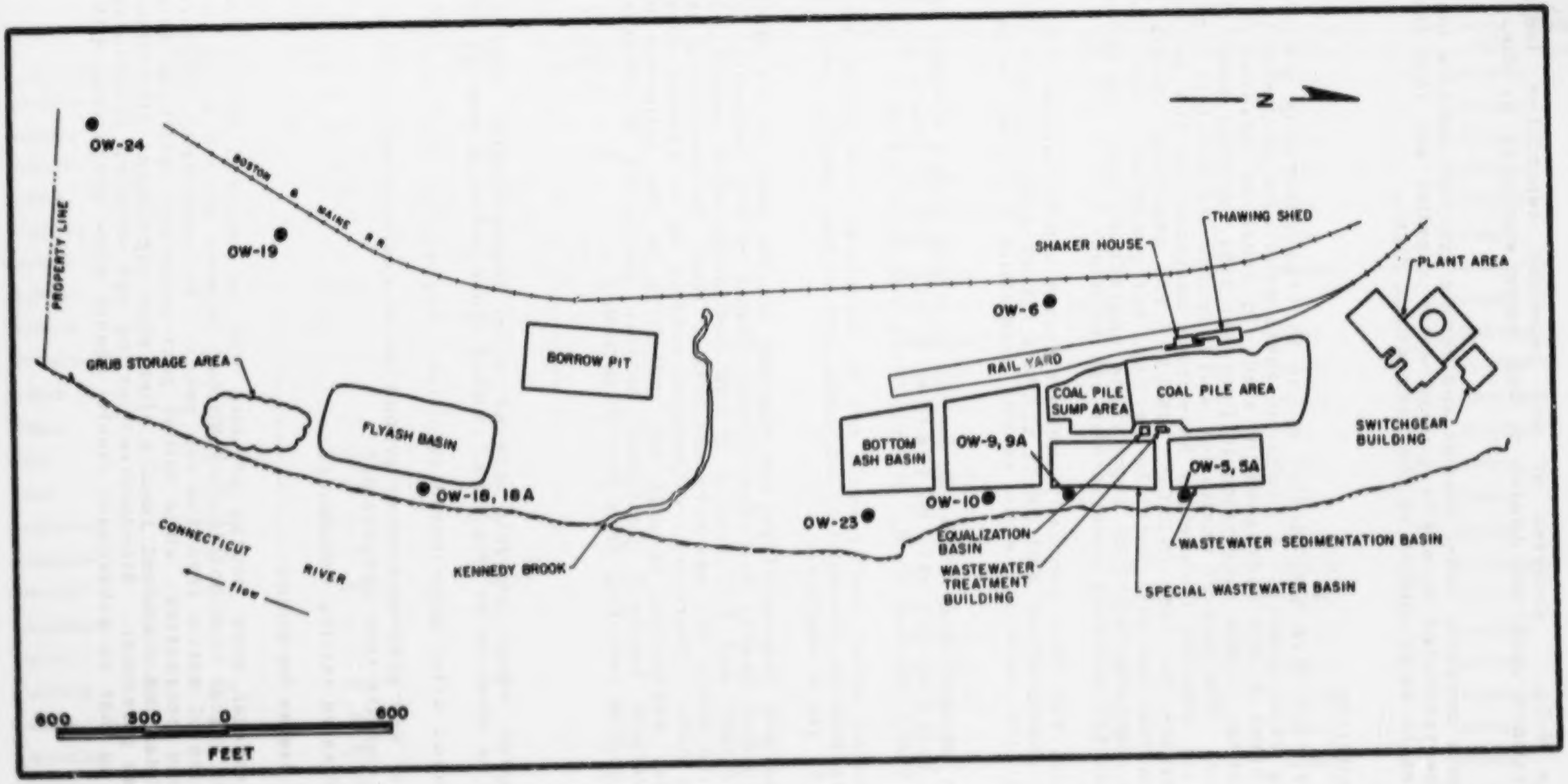
N
OW-24
PROPERTY LINE
BOSTON & MAINE R.R.
OW-19
GRUB STORAGE AREA
FLYASH BASIN
BORROW PIT
OW-18, 18A
CONNECTICUT
RIVER
flow
KENNEDY BROOK
OW-23
BOTTOM ASH BASIN
OW-9, 9A
OW-10
OW-6
RAIL YARD
COAL PILE SUMP AREA
COAL PILE AREA
SHAKER HOUSE
THAWING SHED
PLANT AREA
SWITCHGEAR BUILDING
OW-5, 5A
EQUALIZATION BASIN
WASTEWATER TREATMENT BUILDING
SPECIAL WASTEWATER BASIN
WASTEWATER SEDIMENTATION BASIN
600
300
0
600
FEET

Figure 4-1. Mt. Tom Generating Station Monthly Monitoring Well Locations Relative to Conversion Modifications.

The Northampton Conservation Commission appealed to DEQE the site assignment issued to HWP by the Holyoke Commission of Health for disposal of ash onsite. This appeal requests that DEQE require revisions to the present ground water monitoring program. Alternatives include more extensive testing, at additional locations, for additional parameters, or at increased frequencies. DEQE, the utility and the Conservation Commission presently are negotiating unresolved issues raised by the appeal. Until a decision is reached, DEQE will continue to receive and review the monthly monitoring reports so that corrective action can be taken immediately should any degradation of ground water quality be detected. Also, by March 1983, fly ash will be collected dry for sale or disposal offsite, and the volume of sluicing waters will be reduced from more than a million gallons per day to 375,000 gpd.

At this time, the benefits of lining the wastewater or ash basins are uncertain. Lining the basins would serve to increase overflow discharges directly to the river, while eliminating the attentuation effects currently afforded by leachate migration through the soils. Since no degradation of the ground water by the basin infiltration has been indicated by initial monitoring results, there is no immediate concern over the present basin construction.

4.2.3 Air Quality

4.2.3.1 Fugitive Dust

Fugitive dust may escape from open or unducted sources and be entrained in the atmosphere. Several types of sources may contribute to fugitive dust emissions. Typical sources that might exist at the Mt. Tom generating station operating under the DCO are:

1) Transfer operations - unloading of coal cars, loading and unloading coal from the storage pile, and conveyor transport of coal.

2) Processing operations - coal crushing.

3) Vehicular traffic - construction equipment traffic, automobile and truck operation onsite.

4) Wind erosion - loose material from bare or uncovered construction areas, or from a coal storage pile, picked up by wind action.

Fugitive dust is very difficult to quantify in that there are many variables that significantly affect the emission rates. As a result, it is necessary to limit the discussions of fugitive dust to general patterns that are most probable under the various scenarios.

The health effects of atmospheric particulate matter are dependent upon the chemical species contained within the particles and the particle size distribution. Inhalable size particles, those with diameters smaller than approximately 10 m to 15 m, are more deleterious to health than are larger particles. The preponderance of the mass of fugitive dust particles (typically about 70 percent) is contained in larger particles that are not inhalable and that are furthermore rapidly removed from a plume by gravitational settling. Fugitive dust raised by construction activities and coal handling is generally chemically innocuous.

Low-sulfur Coal Conversion Scenario

The major sources of fugitive dust under this scenario would be the coal transfer and conveying equipment, with some minor contributions by the other above-mentioned sources. The total fugitive dust emission rate would be expected to be small (1.3 g/s) when compared to the particle emission rate from the stack both during the DCO period (82.9 g/s) and following installation of the new precipitator (13.8 g/s).

Because a fugitive dust plume is nonbuoyant and is released near ground level, the ambient concentrations produced by the fugitive dust will be largest very near the sources. The fugitive dust contribution to the total particulate matter concentration at the location of the maximum concentration from the stack plume will be insignificant. Concentrations of fugitive dust outside the Mt. Tom plant boundary due to the low-sulfur coal conversion should be small.

Under the low-sulfur coal conversion scenario, both bottom ash and captured fly ash will be initially sluiced wet to storage ponds onsite. The bottom ash ponds are to be drained (in alternate years) and the ash permanently disposed of onsite. The ash will be damp when spread on the disposal site, and the ash layers will be covered by native soil and vegetation. Under this scenario, the only fugitive dust emissions will be caused by vehicular traffic required in moving the ash from the settling ponds to the final disposal area, and possible wind erosion of the bare topsoil spread over the ash before ground-cover vegetation is reestablished. The new dry ash disposal sysem to be installed will utilize latest technologies to minimize fugitive dust.

Coal Conversion With Other Emission Control Alternatives

The emissions control alternative with the largest bearing on fugitive dust emissions at the Mt. Tom generating station would be the use of limestone wet scrubbers to control SO_2 stack emissions. Limestone wet scrubbing would entail additional facilities for unloading, storing, handling, transporting, and crushing limestone. Wet scrubbing would, on the average, require about one ton of limestone for every 100 tons of coal consumed. Limestone fugitive emissions during maximum rate rail car unloading might infrequently be the largest plant source of fugitives for a short period of time. Limestone scrubbers would cause an increase in fugitive dust emissions over the planned conversion ranging from almost negligible up to possibly doubling it. These emissions would still be very small and not have much effect outside the plant boundaries. Actual particulate emission would be specific to control equipment selected.

If dry scrubbing SO_2 control technology were used instead of wet scrubbing, the potential for fugitive dust emissions from handling of the dry scrubber raw material and waste would have to be considered. It may be assumed that fugitive emissions from a dry scrubber system would be approximately the same as those for the wet scrubber system. However, actual emissions would depend on the type of dry scrubber technology and the engineering details of the system.

Wood Chips as Fuel

Fugitive emissions resulting from the use of wood chips as the primary fuel at the Mt. Tom generating station would depend on the amount of onsite wood chip processing. If the wood chips were burned in the form in which they were brought to the site, and particularly if the water content of the wood chips were still substantial, then little or no fugitive dust emissions would be expected. On the other hand, substantial additional chipping or grinding of dry "as received" wood chips onsite could cause fugitive emissions substantially larger than the coal dust fugitives, unless extensive control measures were undertaken.

Refuse-derived Fuel

Refuse-derived fuel (RDF) would generate fugitive dust emissions similar to those from coal. Processing of refuse into the fuel form would remove most of the water from the refuse; nevertheless the product should be less dusty than coal because of the fibrous nature of much of the original material. Offsetting this to some extent, however, would be the need to handle large quantities of RDF because of its lower heating value. Handling processes for the RDF would be similar to those required for coal, and would occur simultaneously with coal handling in a scenario of primary use of coal with 20 percent heat input by RDF. It is therefore concluded that the fugitive dust production would be roughly the same as the use of coal without RDF.

4.2.3.2 Stack Emissions

A summary table of estimated emission rates for criteria pollutants at the Mt. Tom generating station under the various alternative fuel use scenarios is presented in Table 4-6. ("Criteria" pollutants are those for which EPA has established national ambient air quality standards.)

Sulfur Dioxide

The low-sulfur coal conversion involves essentially no change in SO_2 emission rate for any averaging period of 30 days' duration or longer. However, shorter term increases will be allowed, so long as the 30-day averaging limit is not exceeded; the maximum 24-hour emission rate will be 32 percent larger than the 30-day average. The various alternative fuel options considered in Appendix B (namely, the use of high-sulfur coal plus

TABLE 4-6

MT. TOM GENERATING STATION STACK EMISSIONS OF MAJOR POLLUTANTS (g/s)

	Fuel Use Scenario				
Pollutant	No Action[a]	Low-sulfur Coal Conversion	High-sulfur Coal Plus SO_2 Scrubbing	Coal Conversion Plus 20% RDF	Wood as Primary Fuel
SO_2	400	397 (30-day) 525 (24-hr)	397 (30-day) 525 (24-hr)	326 (30-day) 428 (24-hr)	17.3
PM	8.0[b]	82.9 (DCO period)[c] 13.8 (permanent)	82.9 (DCO period)[c] 13.8 (permanent)	82.9 (DCO period)[c] 13.8 (permanent)	20.7
NO_2	123	124	124	110	115
CO	5.9	6.9	6.9	126	23.0
HC	1.2	2.1	2.1	6.8	23.0

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[a] Assumes a return to oil burning as the utility's selected option.

[b] Assumes that the existing PM control systems reduce PM emissions to the measured value of 0.046 lb PM/10^6 Btu heat input, as indicated by Mt. Tom station stack testing in November of 1980. The permitted maximum emission rate for the no action case (that is, a return to oil burning) (0.12 lb PM/10^6 Btu) corresponds to an emission rate of 20.9 g/s.

[c] Under the terms of the DCO, this rate must be reduced to 60.5 g/s after 8 months of coal burning operation.

additional SO_2 control (scrubbers); the use of refuse-derived fuel (RDF) for 20 percent of the required heating; and the use of wood as the primary fuel), all produce either reductions or no change in estimated Mt. Tom station SO_2 emissions. The reductions range in size from about 19 percent for the use of RDF to 96 percent for the use of wood as the primary fuel.

Particulate Matter

Some fraction of the ash content of any fuel burned at Mt. Tom generating station will escape to the ambient atmosphere through the stack. Under the oil burning alternative, the allowed amount of emitted particulate matter (PM) was determined by the then-applicable SIP limitation of 0.12 lb PM/10^6 Btu heat production. This would correspond to a PM emission rate of 20.9 g/s for full-capacity operation, and an annual average rate of 16.7 g/s (582 ton/year), assuming an 80 percent annual capacity factor. Stack testing of PM emissions at Mt. Tom station under oil burning operation indicates that full-capacity operation of the station produces a PM emission rate of about 0.046 lb PM/10^6 Btu (7.9 g/s), about 38 percent of the old SIP limit.

The low-sulfur coal conversion scenario involves a temporary increase in PM emissions to 82.9 g/s during the period covered by the DCO. (This is to be reduced 60.5 g/s after 8 months by the terms of the DCO.) Subsequent permanent operation using new PM control equipment would produce emissions of 13.8 g/s, the permitted maximum that would be established by the SIP revision lowering the allowed emission rate to 0.08 lb PM/10^6 Btu heat production.

The alternative fuel option coal conversion scenarios, involving additional SO_2 control or use of RDF, would have PM emissions identical to those for the low-sulfur coal conversion. The alternative of using wood chips as the primary fuel was assumed to be limited to a PM emission rate of 20.7 g/s, a value corresponding to the current SIP limit of 0.12 lb PM per 10^6 Btu heat production.

Typically, 75 to 80 percent of the mass of PM released from the stack is in particles with sizes in the inhalable range, smaller than 10 m to 15 m in diameter (Ray and Parker, 1977). This distribution is not expected to greatly differ among the various fuel alternatives, because all of the alternatives will require PM control, which removes the larger size particles with greater efficiency than the smaller size particles.

Nitrogen Oxides

Nitrogen oxides emissions, which are referred to in this document by their nitrogen dioxide (NO_2) equivalent, would increase by approximately 86 percent with the low-sulfur coal conversion. This corresponds to additional NO_2 emissions of about 1,500 tons per year. This estimate of additional NO_2 emissions reflects the difference between a conservative estimate of NO_2 emissions under coal-fired operation, using EPA emission factors (EPA, 1980), and actual NO_2 emissions under oil-fired operation, as determined from stack testing data (NUSCO, 1981d). The use of RDF to provide 20 percent of the plant heat input, or the use of wood chips as the primary fuel, would result in smaller increases in NO_2 emissions - 65 percent and 23 percent, respectively. Diesel trucks transporting ash onsite would indirectly contribute to the NO_2 emissions at the station. These truck contributions would, however, be less than 0.5 percent of NO_2 emissions from normal automobile traffic in the area.

The conservative assumption is made that all nitrogen oxides emissions from the Mt. Tom station are immediately transformed to criteria pollutant NO_2. Maximum ground-level concentrations of NO_2 due to operation of the Mt. Tom station are estimated in Section 4.2.3.3. The air quality effects of NO_2 emissions from a single source, or from a type of source, are complicated by the complex emission pattern for this pollutant (both transportation and stationary sources make significant contributions to atmospheric NO_2 loading), and by the complex atmospheric chemistry that applies. Some of these effects are regional in scale, and are addressed in the Northeast Regional EIS (DOE, 1981).

Carbon Monoxide

The low-sulfur coal conversion involves a 17 percent increase in present CO emissions at Mt. Tom. At an 80 percent annual average capacity factor, station operation would result in annual average CO emission rates of 4.7 g/s (164 tons/year) and 5.5 g/s (192 tons/year), respectively, for oil burning operation and for the low-sulfur coal conversion. It should be noted that these emission rates are insignificant when compared to emissions from automobiles in the area.

Substantial increases in CO emission rates would result from the alternative fuel options. Wood chips would produce a CO emission rate of 18 g/s, an increase of 390 percent compared to the oil burning operation. The use of RDF to supply 20 percent of the station's heat energy requirement would yield a CO emission rate of 101 g/s, an increase of 2,140 percent above the rate with the oil burning operation. However, even these emission levels are minor in comparison to those made by local automobile traffic. None of the fuel alternatives would result in significant ground-level CO concentrations (see Section 4.2.3.3).

Hydrocarbons

The low-sulfur coal conversion will result in a 75 percent increase (31.5 tons) in stack emissions of HC above the level of oil of 42 tons per year. There will be reduced evaporative losses from elimination of oil handling of approximately one ton of hydrocarbons per year, for a net HC emissions increase of 73 percent due to the oil-to-coal conversion. When this increase in station emissions is compared to total emissions for the Massachusetts portion of the AQCR, the change due to the NOE amounts to about 0.04 percent. According to EPA regulations (40 CFR 51.18(j)(1)(xiii)), the minimum increase in HC emissions that is considered significant is 40 tons per year. The low-sulfur coal conversion would result in an HC emissions increase of about 31 tons per year, and thus only an insignificant effect on attainment of the ozone ambient air quality standard is expected.

All of the alternative fuel options would increase the HC emission rate by more than the oil or low-sulfur coal conversion scenarios. Because the Mt. Tom station is located in an ozone nonattainment area, the increased HC emissions are a significant adverse air quality factor for these other fuel alternatives.

EPA has proposed revocation of the HC 3-hr (9-12 AM) ambient air quality standard (46 FR 25655, 8 May 1981). The ambient standard is being proposed for rescission because HC pollutants, as a class, have not been shown to have adverse health effects. The HC standard is intended only as a guide for planning to achieve attainment with the ozone ambient standard.

Some trace components of HC are known, or suspected, to have adverse health effects. For example, polycyclic aromatic hydrocarbons (PAH), are mutagenic in laboratory tests and are suspected human carcinogins. The details of emissions of PAH and the chemical reactions they may undergo in the atmosphere are currently only very poorly known. Power plant coal use may produce more PAH than does oil burning. However, the greatest human exposure to PAH is most likely produced by burning wood in residential heating.

A potential air quality effect from the use of RDF could be the release of toxic HC gases to the atmosphere. Such extremely toxic gases as dioxins have been identified in small concentrations in RDF flue gas streams (Ogg and Menczel, 1981). The extent of such emissions and the potential health hazards are currently only very poorly known.

Ozone

Ozone (O_3) is not directly emitted by the Mt. Tom generating station stack, but precursors to O_3 are emitted. In the presence of intense sunlight, a complex chemical reaction between nitrogen oxides and non-methane hydrocarbons produces ozone and peroxyacetyl nitrates (PAN); large numbers of deleterious by-products (nitrate aerosols) are also formed. Changes in the generating station's emissions in response to an NOE could contribute to the formation of only minute amounts of ozone and other photochemical oxidants in comparison to automobile traffic.

Trace Elements and Radionuclides

The conversion from oil to coal combustion at Mt. Tom generating station involves a change in the mix of trace elements that are released to the atmosphere through the stack. This is due to the different trace elements found in the fuels themselves, which in general are different for coal and oil due to the different geologic and chemical histories of the fuels, and their different abilities to mobilize trace elements encountered in the earth.

Table 4-7 shows typical differences in the trace element composition of coal and oil. This table is adapted from one in ERDA (1977). The information derives from Sax (1974). Note that the trace element composition given in the table is not necessarily representative of the fuels consumed at Mt. Tom; individual element concentrations can vary greatly in fuel from different sources, and even in fuel from the same source at different times.

Many of the trace elements in the fuel are captured in the ash, and therefore for the most part do not reach the ambient air. The chemistry involved is complex, and in general it is not possible to reliably calculate stack emissions from a knowledge of the trace element composition of the fuel. The toxicity of the trace elements in the chemical combinations in which they are released into the atmosphere also varies greatly. For these reasons, it is not possible to quantify the trace metal air quality effects of the fuel switch at Mt. Tom generating station. Roughly and qualitatively speaking, of the trace elements most thought to contribute to human toxic exposure, the effect of a conversion from oil to coal would be to reduce exposure to vanadium and cadmium, and to increase exposure to beryllium, lead, and bismuth. The levels of exposure to these elements generated by the conversion are very small in comparison to those known to cause adverse health effects. It can therefore be reasonably concluded that no significant health hazard is presented from these emissions.

Some of the trace elements in coal are radioactive, and the process of coal combustion can release radionuclides to the atmosphere or concentrate them in the ash. Either of these processes has some potential for increasing human exposure to ionizing radiation above that due to the background level. The principal radionuclides that are emitted by coal-fired power stations are Uranium-238 and its decay products, Thorium-232 and its decay products, and Radon-222 (a decay product of Radium-226).

The USEPA has announced its decision to list radionuclides as hazardous air pollutants (EPA, 1979), and new coal-fired power stations will possibly be required to meet emissions limitations for these substances under regulations that are to be promulgated in the future. As of 27 April 1981, EPA has decided to postpone issuance of such emission standards.

The EPA has produced estimates (EPA, 1979) for a model coal-fired power station "...representative of new plants releasing one percent of the fly ash." For such a model power station in a rural setting, USEPA estimates that the maximally exposed individual will receive radiation dose rates of 2.1 mrem/yr to lung tissue and 16.0 mrem/yr to bone. These estimates may be compared to estimated average background U.S. dose rates - 180 mrem/yr to the lung, and 120 mrem/yr to bone (NCRP, 1975).

Lead

Lead (Pb) generally exists as a trace contaminant in coal, and, to a lesser degree, in oil. Typical Pb concentrations in fuel are 26 ppm for coal and 0.3 ppm for oil, although wide variations in these values occur for fuels from different sources. Stack emissions of Pb from powerplant fuel combustion is a very minor source of ambient lead when compared to other sources such as automobile leaded gasoline combustion or primary lead smelter emissions.

Fuel combustion at electric generating stations produces ground-level Pb concentrations that are very much smaller than the ambient air quality standard of 1.6 $\mu g/m^3$ Pb for an averaging period of a calendar quarter. Estimated maximum ambient Pb concentrations resulting from the Mt. Tom low-sulfur coal conversion are presented in Section 4.2.3.3.

4.2.3.3 Dispersion Modeling Results

In this section, the primary analysis is concerned with an assessment of the low-sulfur coal conversion's effect on ambient air quality in the area of Mt. Tom generating station. The effects on ambient air quality are assessed for conditions during the DCO period, and for permanent plant operation subsequent to the DCO period. For purposes of PSD increment consumption, there will be no increases in pollutants attributable to the increased emissions from the facility after conversion (see Section 3.3.3).

TABLE 4-7

TRACE ELEMENT CONCENTRATIONS IN FOSSIL FUELS

Element	Fossil Fuel Concentration (ppm)[a]	
	Coal[b]	Oil
Li	65	
Be	3	0.0004
B	75	0.002
Na	2,000	2
Mg	2,000	0.1
Al	10,000	0.5
P	500	
S	20,000	3,400
Cl	1,000	
K	1,000	
Ca	10,000	5
Sc	5	0.001
Ti	500	0.1
V	25	50
Cr	10	0.3
Mn	50	0.1
Fe	10,000	2.5
Co	5	0.2
Ni	15	10
Cu	15	0.14
Zn	50	0.25
Ga	7	0.01
Ge	5	0.001
As	5	0.01
Se	3	0.17
Rb	100	
Sr	500	0.1
Y	10	0.001
Mo	5	10
Ag	0.5	0.0001
Cd		0.01
Sn	2	0.01
Ba	500	0.1
La	10	0.005
Ce	11.5	0.01
Pr	2.2	
Nd	4.7	
Sm	1.6	
Eu	0.7	
Gd	1.6	
Tb	0.3	
Ho	0.3	
Er	0.6	0.001
Tm	0.1	
Yb	0.5	
Lu	0.07	
Re	0.05	
Hg	0.012	10[c]
Pb	25	0.3
Bi	5.5	
U	1.0	0.001

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[a] These average values were obtained from a review of published values for the abundances of elements in coal and fuel oils. Wide variations exist for a given element and the figures are presented as reasonable estimates from available data.

[b] Coal and lignite are combined in this representation.

[c] This Hg value may be unrepresentative of petroleums in general. It is the only published value for Hg in fuel oils of which we are aware. The samples came from the Cymric oil fields of California, an area near known Hg deposits.

Source: Sax, 1974.

The results obtained by the dispersion modeling for the low-sulfur coal conversion are summarized in Tables 4-8 through 4-10. The dispersion modeling results are based on extensive modeling performed by NUSCO. The modeling exercise performed by NUSCO was reviewed by the EPA Region I and by Dames & Moore, as consultants to DOE, and was judged adequate. See Appendix B for a detailed description of the modeling exercise.

The DCO was issued with respect to the pollutant PM. Tables 4-8 and 4-9 together provide a demonstration that the Mt. Tom station emissions during the DCO period will not cause or significantly contribute to a violation of the NAAQS for either PM or SO_2. The total calculated 24-hour ambient concentration for SO_2 (364.7 $\mu g/m^3$) is only slightly less than the NAAQS of 365 $\mu g/m^3$. Because of the conservative way in which the calculation was performed, the tabulated value is an upper bound. Table 4-9 shows the calculated MOU coal conversion contribution to PM concentrations at monitor sites in AQCR 42 at which PM NAAQS violations have been observed. In no case does the Mt. Tom station contribution exceed the significance levels of 5.0 $\mu g/m^3$ for the 24-hour averaging period or 1.0 $\mu g/m^3$ for the annual average.

The modeling results for permanent (that is, subsequent to the DCO period) operation of Mt. Tom generating station under the low-sulfur coal conversion scenario are presented in Table 4-10. The pertinent ambient air quality standards are also presented for comparison. The total ambient concentration values given are conservative estimates as indicated above.

Examination of Table 4-10 reveals total calculated ambient concentrations exceeding the standards for PM (secondary standards), for CO (8-hour standard), and for Pb. In each case, the standard is violated by the background contributions alone, irrespective of model calculations. The Mt. Tom station contributions are smaller than the EPA minimum significant impacts for model calculations of PM and CO concentrations. The minimum significant impact levels for PM are 5 $\mu g/m^3$ for the 24-hour average and 1.0 $\mu g/m^3$ for the annual average, and for CO they are 500 $\mu g/m^3$ for the 8-hour average and 2,000 $\mu g/m^3$ for the 1-hour average. The annual average NO_2 contribution by the Mt. Tom station is 0.9 $\mu g/m^3$, which is smaller than the significant impact level of 1 $\mu g/m^3$. No significance level for modeling of Pb has been established, but note that the calculated Mt. Tom station contribution is smaller than the ambient standard by a factor of 500. Thus, it is demonstrated that the permanent operation of the Mt. Tom station under the low-sulfur coal conversion will not cause or significantly contribute to any violation of the ambient air quality standards.

Estimates of the air quality effects of the various fuel use alternatives are presented in Table 4-11. The values presented are estimated based on the low-sulfur coal conversion dispersion modeling as described in Appendix B. Examination of this table indicates that predicted concentrations of the various pollutants at Mt. Tom would not preclude the use of most of the fuel use alternatives. The exception is the use of high-sulfur coal together with scrubbing. In this case the reduced buoyant plume rise associated with use of the scrubber systems leads to a significant increase in estimated maximum concentrations, and the conservative upper bound for the 24-hour SO_2 total ambient concentration would exceed the NAAQS of 365 $\mu g/m^3$. This does not mean that the use of a scrubber would necessarily produce unacceptable air quality effects. It does mean that if this alternative were eventually chosen for the Mt. Tom generating station, careful design of the control system would be necessary to avoid (and to demonstrate avoidance) of a violation of the NAAQS.

The 1-hour average NO_2 concentrations given in Tables 4-10 and 4-11 are presented to allow comparison with the level set by the DEQE of 320 $\mu g/m^3$. A level of 320 $\mu g/m^3$ for a 1-hour NO_2 ambient concentration is stipulated as the maximum level to avoid effects potentially injurious to health. This level is not listed in the state regulations as an ambient air quality standard, but it is a part of DEQE policy for new source review of NO_2 sources that result in increased emissions greater than 250 tons per year. If the values indicated in Table 4-11 are added to a background level of 175 $\mu g/m^3$ (from Table 3-9), a conservative comparison to the DEQE level results. (This is a conservative comparison because the urban background concentration used is expected to be larger than the NO_2 background at the point of maximum contribution from the Mt. Tom station.) This comparison is shown explicitly in Table 4-10 for the low-sulfur coal conversion, where a total 1-hour estimate of 259 $\mu g/m^3$ results. Examination of Table 4-11 reveals that the only fuel alternative that might jeopardize the 320 $\mu g/m^3$ level is that of the use of high-sulfur coal together with scrubbing. If the use of a scrubber were eventually required, then a more careful modeling analysis would be called for, as was also indicated above in the discussion of the short-term SO_2 NAAQS.

TABLE 4-8

CALCULATED AIR QUALITY EFFECTS IN THE MT. TOM STATION AREA FOR POLLUTANT EMISSIONS DURING THE DCO PERIOD UNDER THE LOW-SULFUR CONVERSION, COMPARISON WITH PRIMARY AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	Modeled Contribution: Mt. Tom DCO	Modeled Contribution: Other Source	Measured Background	Total Calculated Ambient Concentration	Primary Ambient Air Quality Standard
SO_2	24-hr	149.1	76.7	138.9	364.7	365
	Annual	3.0	21.3	32	56.3	80
PM	24-hr	22.4	7.1	185	214.5	260
	Annual	0.6	3.1	63	66.7	75

Concentrations given in μg/m^3.

TABLE 4-9

CALCULATED YEARLY MAXIMUM PM CONTRIBUTIONS DUE TO THE DCO-ALLOWED MT. TOM STACK EMISSIONS AT NONATTAINMENT MONITOR LOCATIONS IN AQCR 42

Location	Averaging Period	1977	1978	1979
Chicopee (939 Chicopee St.)	Annual	0.18	0.21	0.20
	24-hr	1.88	2.47	2.48
Waterbury (DOT Entrance to I-84)	Annual	0.11	0.12	0.12
	24-hr	1.53	1.13	1.81
Waterbury (Waste Treatment Plant)	Annual	0.11	0.11	0.11
	24-hr	1.41	1.01	1.69
New Haven (677 State St.)	Annual	0.12	0.16	0.14
	24-hr	1.11	1.12	1.34

Concentrations in μg/m^3.

TABLE 4-10

CALCULATED AIR QUALITY EFFECTS IN THE MT. TOM STATION AREA FOR PERMANENT OPERATION UNDER THE LOW-SULFUR COAL CONVERSION. COMPARISON WITH AMBIENT AIR QUALITY STANDARDS

(Concentrations given in $\mu g/m^3$)

Pollutant	Averaging Time	Modeled Mt. Tom Contribution	Modeled Other Source Contribution	Background	Total Calculated Ambient Concentration	Ambient Air Quality Standards	
						Primary	Secondary
SO_2	3-hr	241	166	276	683	--	1,300
	24-hr	149.1	76.7	138.9	364.7	365	--
	Annual	3.0	21.3	32	56.3	80	--
PM	24-hr	3.7	7.1	185	195.8	260	150
	Annual	0.1	3.1	63	66.2	75	60
NO_2	Annual	0.9	--	45	45.9	100	100
	1-hr	84.0	--	175	259	320[a]	
CO	1-hr	4.7	--	19,480	19,485	40,000	40,000
	8-hr	2.3	--	11,920	11,922	10,000	10,000
Pb	Calendar Quarter	0.003	--	2.9	2.9	1.5	1.5

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[a] The 1-hr NO_2 level of 320 $\mu g/m^3$ is not an ambient air quality standard, but is a part of the policy of the DEQE for new source review.

TABLE 4-11

ESTIMATED MAXIMUM MT. TOM GENERATING STATION CONTRIBUTIONS TO AMBIENT CONCENTRATIONS FOR ALTERNATIVE FUEL USE SCENARIOS
(Concentrations in $\mu g/m^3$)

Pollutant	SO_2			PM		NO_2		CO		Pb
Averaging Time:	3-Hr	24-Hr	Annual	24-Hr	Annual	1-Hr[a]	Annual	1-hr	8-hr	Calendar Quarter
Low-sulfur Coal Conversion										
DCO Period	241	149	3.0	22.4	0.6	84	0.9	4.7	2.3	0.003
Permanent Operation	241	149	3.0	3.7	0.1	84	0.9	4.7	2.3	0.003
No Action (Return to Fuel Oil)[b]	184	114	3.0	5.6	0.2	46	0.5	4.0	2.0	0.0004
High-sulfur Coal with Scrubbing[c]										
DCO Period	434	268	5.4	40.3	1.1	151	1.6	8.5	4.1	0.005
Permanent Operation	434	268	5.4	6.7	0.2	151	1.6	8.5	4.1	0.005
Coal Conversion with 20% RDF										
DCO Period	196	121	2.5	22.4	0.6	75	0.8	84.8	40.1	0.003
Permanent Operation	196	121	2.5	3.7	0.1	75	0.8	84.8	40.1	0.003
Wood Chips as Primary Fuel[d]	8	5	0.1	5.6	0.2	78	0.8	15.7	7.7	--

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[a] For comparison with the level of 320 g/m^3 for a 1-hr NO_2 concentration, a health-related maximum level that is part of DEQE new source review policy. See text discussion in Section 4.2.3.3.

[b] For estimation of the maximum PM concentrations, the Mt. Tom station PM emission rate was assumed to be the permitted limit of 0.12 lb/10^6 Btu (20.9 g/s) rather than the measured value of 0.046 lb/10^6 Btu (8.0 g/s) obtained by stack testing.

[c] Reduced buoyant plume rise compared to the MOU conversion is assumed to increase concentrations by a factor of 1.8.

[d] It is assumed that the stack exit characteristics for wood burning are the same as for coal burning. This would not likely be true, but engineering data to support any other assumption are unavailable.

4.2.3.4 Acid Deposition and Other Atmospheric Chemistry Effects

As stated in Section 2.7 of this document the NEREIS has discussed the potential contributions of coal conversion of up to 42 plants to acid deposition (DOE, 1981). Additional brief comments on acid deposition are included here because of public concerns raised during the scoping process with regard to potential impacts from the Mt. Tom conversion on the three major reservoirs in central and eastern Massachusetts: Quabbin Reservoir (14 to 22 miles east and northeast of Mt. Tom), Wachusett Reservoir (45 miles east), and Sudbury Reservoir (44 miles east).

While acid deposition is generally thought to be affected by increased emissions of SO_2 and NO_2 that have resulted from man's activities, the relationships between the amounts of SO_2 and NO_2 emitted and the concentration of atmospheric acid downwind are very complex and not yet understood. In addition, the process by which strong acids are formed and transported in the atmosphere and then deposited, wet and dry, on sensitive areas is only partially understood at present, and the effects of weakly acidic dry deposition (SO_2 and NO_x) are even less understood. Another unknown involves the relative effects of sulfur and nitrogen oxides. Although it is believed that NO_x may be less harmful to aquatic ecosystems than SO_x, how much less has not been established. Due to these and other uncertainties, current knowledge of the chemical and physical mechanisms affecting acid deposition does not allow a definitive response to concerns about potential impacts on the reservoirs.

However, comparison of the predicted changes in pollutant levels (Tables 4-10 and 4-11) due to the Mt. Tom conversion is possible and clearly indicates that the increases of SO_2 and NO_x can be considered relatively minor in the short term (less than 30-day periods) and unchanged in the annual, especially when compared to the ambient air quality standards and existing background levels.

4.2.4 Biological Resources

4.2.4.1 Aquatic Biology

In the summer of 1974, the Massachusetts Division of Fisheries and Wildlife conducted a sampling program to study the biological impact of the Mt. Tom generating station's cooling water system. The shape of the thermal plume created by the warmer discharge water depends on river flow, which varies seasonally. During high spring flows, the plume is squeezed against the bank, extends approximately 2,000 feet downstream, and contacts about 5 acres of river bottom. During low summer flows, the plume spreads more than during spring flows (becoming only 3 feet thick), extends approximately 3,200 feet downstream, spreads across to the opposite shore, but contacts only 3 acres of river bottom (Henry and others, 1974). According to NUSCO, during the winter when river temperatures are lower, the discharged water has the same amount of heat but less volume. When compared to the summertime discharge, the cooling water flow rate is about half and the temperature differential (25°F to 30°F) is about double. Modeling studies (Harleman and Stolzenback, 1972) show these conditions produce a shallower plume with a larger surface area.

A 1974 study (Henry and others) showed that some resident fish species favored the plume (approximately twice as many fish were sampled within the plume as outside it); more fish are therefore attracted to the area of the plant cooling water intake system. An electric fish screen on the intake system, however, keeps fish impingement losses low; an estimated 315 fish were impinged from June through September. This figure may be compared to the number of fish passing the weir at Holyoke dam - nearly 600,000 a year (Table 3-15). Entrainment of larval fish was not studied.

The plant is expected to increase production from its 1976 annual average 62 percent of capacity to 80 percent following the conversion to low-sulfur coal. While this increase will change the amount of time the cooling system is emitting heated water (and the volume of water), it will not affect either cooling water flow rates or temperature changes. The cooling system will be operating more hours per week, so more fish and fish larvae will be entrained on intake screens. Since the number of fish impinged is low, the increase should remain relatively low. Because the station uses only a small percentage of river flow (see Section 3.2.1), larval entrainment should probably not be a serious problem.

Increased generation results in a more constant thermal plume which subjects fish to less stress than does frequent temperature changes; however, a constant plume might attract more fish particularly in the winter, subjecting more fish to thermal shock during temporary plant shutdowns. The probability of thermal shock at the Mt. Tom generating station site is low, since its cooling water discharge is not confined in a canal and can mix more readily with available river water; no large fish kills have been reported during station operations in the past. In summary, increased power generation is not expected to significantly endanger fish populations in the Connecticut River.

Discharges of untreated wastewater from the site are not expected to occur. However, if some 800,000 gallons of untreated ash pond waste were discharged to the river, this could be considered a worst case event. In the immediate area of the discharge of such material into the Connecticut River, runoff water from ash disposal sites could contain high levels of heavy metals (see Section 4.2.2 and Tables 4-1 and 4-2) and could produce long-term results. The levels of toxic materials might not be high enough to cause direct mortality, but heavy metals in low concentrations can inhibit reproductive success in many organisms. If releases occurred during periods when many larval fish were present, a significant reduction in successful maturation could occur. Indirectly, certain species (such as the shortnose sturgeon) can concentrate heavy metals because of specialized feeding methods, etc., and a possible long-term reduction in reproductive success might occur. The improbability of major untreated discharge and the presence of sensitive species in the immediate area of the discharge make these impacts unlikely, especially taking into consideration that after March 1983 only bottom ash will be wet sluiced to ponds (375,000 gpd).

Benthic invertebrates are particularly susceptible to low levels of toxic metals. Many of these organisms concentrate heavy metals because of their feeding methods, and a long-term decrease in numbers of benthos could occur if large quantities of water containing high levels of heavy metals occurred. Additionally, since these organisms are the base for much of the system's food chain, changes in their numbers could result in decreased fish production. However, since all discharges will be treated, significant impacts to benthic invertebrates are not expected.

The movement of potentially toxic materials through ground water is a possibility. A study by Gibbs & Hill (1981) indicates that there are increased concentrations of some metals (copper and iron) and other substances in ground water near the existing Mt. Tom coal pile and ash ponds. Under the low-sulfur conversion, the coal pile area has been lined to prevent contamination from this source. The fly ash and bottom ash ponds are not presently scheduled for lining, and leachates from these sources would enter the ground water regime.

The present ground water contamination results in only minute changes in the water quality of the Connecticut River itself (Gibbs & Hill, 1981). However, even very small changes in the concentrations of certain elements (i.e., copper) in the river can adversely affect migration runs of certain fish, especially salmon. This problem of ground water contamination cannot be adequately evaluated by examining the changes in concentrations of single parameters. It is well established that Atlantic salmon respond adversely to low levels of copper (DeCola, 1970). However, the concentration which will elicit avoidance reactions is dependent upon the alkalinity of the water. The higher the alkalinity the higher the copper concentration must be to trigger an avoidance reaction in the fish. Of course, extremely high alkalinities themselves will adversely affect fish. Additionally, some species of fish respond adversely to low concentrations of other substances, such as zinc, which would also be released from the Mt. Tom site. Acting together zinc and copper might affect fish at lower concentrations than is required for a single element.

The problem of the effects of ground water contamination upon the Connecticut River and on migratory fish is thus exceedingly complex. At the present time no adverse effects seem to be occurring, and the release of materials in the river does not appear to be a problem. Ground water quality will be monitored over a long-term period. Any changes in water quality could, therefore, be correlated with any changes in biota, and remedial action taken. Wet sluicing of fly ash (875,000 gpd) is presently permitted only through March 1983; after that date, bottom ash only will be wet sluiced to one of the two bottom ash basins at a rate of approximately 375,000 gpd, further decreasing the potential for contamination.

4.2.4.2 Terrestrial Biology

Flora

Air quality changes will have little or no impact on surrounding vegetation. With coal combustion, the maximum expected 3-hour concentration of SO_2 (490 g/m^3 or 0.17 parts per million), is equivalent to minimum threshold concentrations that might cause some damage to the most sensitive plant species in their most sensitive stages of growth (Argonne National Laboratory, 1977), and is well below the level for causing acute damage to the eastern white pine (0.35 ppm), the most sensitive forest species in the northeast (Miller and McBride, 1975).

The principal adverse impact on flora would be the possible conversion of approximately 15 acres of cornfield into an ash disposal site. This loss would not significantly affect the availability of productive farmland, as discussed in Section 4.2.5.1.

Fauna

There would be a loss of wildlife feeding habitats in the cornfield (if developed for ash storage) and in the overgrown ash ponds during the life of the project. However, these feeding areas are very small, and when considered relative to that available in the nearby region the impact on wildlife from direct loss of habitat would be insignificant.

The increase in noise levels around the plant resulting from the conversion to coal will disturb animals around the plant site, possibly causing decreases in avian nesting success due to the inability of birds to maintain territories because of the noise. However, this is a very local problem and should not have a significant impact on the wildlife in the region.

There will be an increase in particulate discharge rates during the period of the DCO. This will increase the dispersion of small amounts of heavy metals into the atmosphere and possibly into surrounding terrestrial and aquatic systems. However, such an impact should not have any direct effect on the region's plants or wildlife.

4.2.4.3 Threatened and Endangered Species

Air quality changes projected for coal conversion will not adversely affect the woodlands hosting the terrestrial threatened and endangered animals listed in Table 3-16; thus, it will not indirectly affect these animals by endangering their habitat.

The expected increase in cooling water system throughput may increase the frequency of fish impingement on the intake screens. Two species listed in Table 3-16, the white and channel catfish, were among the fish collected from the intake screens in the 1974 thermal plume study, when the station was operating at base load. Only one white catfish was collected, but channel catfish were the most frequently impinged fish. Even so, the number collected was low (16 total during eighteen 24-hour samples). These impingement losses do not represent a significant impact on these species.

4.2.5 Sociocultural Resources

4.2.5.1 Land Use

Under the originally proposed conversion alternative, construction activities have been confined to the station as planned. It is unlikely that many serious impacts to land uses in the vicinity of the plant have occurred. This is, however, not the most acceptable alternative because of the potential impacts to the floodplain (see Section 4.2.2.1) and to prime farmland.

If enlargement of the presently developed ash storage capacity were necessary at some time in the future, possible impacts would include the conversion of 15 acres of prime farmland to industrial use. This onsite acreage is an insignificant portion (less than

0.05 percent) of total prime farmland in the county (approximately 33,584 acres). The amount of Winooski silt loam in the county is approximately 1,078 acres; thus the area onsite represents only about 1.4 percent of the total acreage of Winooski soils in the county.

The existing ash ponds and landfill onsite supported a vegetative cover of trees and shrubs. It is probable that the reconstructed ponds and landfill areas can be returned to useful agricultural purposes when the plant is decommissioned.

Alternatives to onsite storage of ash include sale and offsite disposal. If offsite ash disposal is required, and presently active waste facilities are not available, several acres of land would have to be acquired and roads perhaps constructed to the site. The acreage to be used would be approximately the same as for onsite storage. If a market can be found, especially for fly ash, land use requirements would be greatly reduced.

4.2.5.2 Visual

The addition of a 50-foot high coal pile decreases the visual aesthetics of the plant. However, the basic industrial nature of the facility diminishes the importance of this effect; no significant impact to the area's aesthetics is expected.

4.2.5.3 Transportation

As a result of the conversion, the Mt. Tom generating station will consume 384,000 tons of coal per year at 80 percent of generating capacity. Coal is to be delivered in 7,000-ton capacity trains about once every 5 days. There are no apparent constraints to supplying coal to the Mt. Tom generating station. Also, if all solid wastes are disposed of onsite, there would be no impact on public roads because coal would be delivered by rail and no more than 20 additional employees would be commuting to the plant.

The utility estimates (NUSCO, 1981d), that if all fly and bottom ash are carried offsite by truck either for offsite storage or for sale and reuse, and if the trucks are 18-wheel vehicles capable of carrying about 12 tons of ash in each load, it would be necessary to carry away about 61 loads each week. The trucks would be able to enter Route 5 at the plant, in an area with little or no near-by development.

If the ash were sold, the possibilities for using railroad cars would depend upon such factors as the proximity of the recycling site to the railroad, the availability of covered cars (similar to tank cars) for the ash, and the relative costs of truck and railroad shipment under the circumstances of each case. About 30 rail car loads a week would be necessary to transport all fly and bottom ash in this manner (NUSCO, 1981d). If the ash must be carried to an offsite landfill, transportation costs of $10 per ton are estimated, totalling as much as $400,000 per year (NUSCO, 1981d).

4.2.5.4 Historic, Cultural, and Archaeological Resources

As discussed in Section 3.5.6, two areas of historical interest occur onsite. The utility ceased work in the areas of concern pending additional archaeological studies (NUSCO, 1981d). If it is necessary to go offsite for ash disposal it is likely that a cultural resources survey would be necessary in the area selected for storage. The survey would be performed before any construction was begun.

4.2.5.5 Sound Quality

The low-sulfur operational oil fired power plant has been modified to burn low-sulfur coal. This change required the activation of preexisting equipment and the installation of new equipment. The principal noise sources associated with this change are listed in the following tabulation together with their A-weighted sound levels.

	A-weighted Sound Level
1. Coal car shaker[a]	59 dB @ 1,750 ft
2. Crusher[b]	89 dB @ 30 ft
3. Tractor dozer[c]	87 dB @ 50 ft
4. Transfer equipment, i.e. conveyors[d]	82 dB @ 50 ft
5. Train operations - 15 mph[c]	71 dB @ 50 ft

[a] Northeast Utilities
[b] D&M files
[c] EPA data
[d] Edison Electric Institute "Electric Power plant - Environmental Noise Guide"
Source: NUSCO, 1981d

Of the above principal noise sources it is clear that the coal car shaker is the dominant noise generator (Table 4-12). To prevent excess emissions to the homes at Thermopyle, an acoustic barrier approximately 130 ft long and 40 ft high has been built. This barrier is located about 25 feet from the shaker house between it and the river, thus preventing straight-line noise emissions from the shaker house to Thermopyle (see Figure 3-5).

A barrier noise control calculation (Table 4-12) indicates that this barrier should reduce noise levels in the direction of Thermopyle by about 20 dB.

The noise emissions from the above principal noise sources were added to the pre-conversion power plant noise sources - fans, blowers, pumps, etc. - when the conversion was accomplished. Sound levels at the noise sensitive areas discussed earlier are due to the pre-conversion powerplant operation, highways, and other noise sources, far and near.

The contributions of the coal handling principal noise sources to the ambient sound levels at the noise sensitive areas are presented in Table 4-13. The transmission of sound over large distances is a complex process dependent upon environmental conditions such as humidity, wind, temperature gradients, foliage, etc. Except for conditions during a temperature inversion and a windy day, the atmosphere, and foliage attenuate transmitted sound. Due to a lack of data, the computations used to develop data presented in Table 4-12 are conservative, that is, higher than expected sound levels are presented. Under certain wind conditions or during a temperature inversion, sound levels from the plant may be about 5 dB higher.

These contributions are added to the baseline sound levels to estimate future day/night sound levels L_{dn}. The results are shown in Table 4-13.

Noise generated by coal handling activities at the power plant will be below the present ambient sound levels at the Mt. Tom community (about 3,500 feet from the plant) and at the Holyoke Country Club (1,500 feet distance) and will therefore be masked by the highway traffic noise. But, at Thermopyle (1,650 feet across the Connecticut River) the day/night sound levels will not be diminished by natural or manmade barriers and will be increased by about 5 to 10 dB. Noise from the coal handling will be discernible even though the shaker noise is reduced by use of a barrier. The major coal handling contribution to Thermopyle noise levels are the dozer and crusher since the shaker is effectively quieted by the barrier.

The change in ambient sound level of 5 to 10 dB is cause for some concern since the residents may be disturbed. But, an L_{dn} = 60 dB is 5 dB below the short-term community sound level goal of the U.S. Environmental Protection Agency and only 5 dB above their long-term goal. An area with an L_{dn} = 60 dB is classified by the Federal Department of Housing and Urban Development as "satisfactory" for new housing (HUD Environmental Criteria and Standards 24CFR51, July 1979).

Massachusetts does not have a clear limit on industrial noise in a residential area. Regulation 10 "noise" does not permit..."unnecessary emissions from said source of sound that may cause noise." The Bureau of Air Quality Control of the Commonwealth of Massachusetts has established noise control guidelines. A community sound level criteria developed by them states "...Approval for the facility will be granted if the installation or modification of the primary noise survey(s) does not: 1. Increase the broad band noise level in excess of 10 dB (A) above ambient..." Thus, the coal conversion will probably comply with these Commonwealth of Massachusetts guidelines.

TABLE 4-12

NOISE SOURCE CONTRIBUTIONS

	Mt. Tom[a]	Holyoke[b]	Thermopyle
Distance	3500'	1500'	1650'
Coal Car Shaker[c]	53 dB	45 dB	40 dB
Crusher	48 dB	30 dB	54 dB
Dozer	50 dB	43 dB	57 dB
Transfer Equipt.	45 dB	38 dB	52 dB
Train, 15 mph	34 dB	27 dB	41 dB
Total A-weight Sound Level	56 dB	48 dB	62.5 dB

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[a] Community (see Figure 3-5).

[b] The Holyoke Country Club is higher than the power plant resulting in about 15 dB attenuation.

[c] Includes effect of acoustic barrier.

Source: NUSCO, 1981d.

TABLE 4-13

AMBIENT SOUND LEVELS AT NOISE SENSITIVE AREAS

Noise Sensitive Location	Baseline L_{dn}	Noise Source Contribution L_A (when operating)	Future Ambient L_{dn} Change
Community of Mt. Tom	60-65	56	60-65
Holyoke Country Club	55-60	48	55-60
Thermopyle	50-55	60	60

Holyoke's Noise Performance Standards use absolute frequency ranges and are therefore not enforceable. Present sound levels do, however, exceed the noise level criteria. At the country club and in the community of Mt. Tom no change in sound quality is anticipated. Thus, the coal conversion will not further degrade the sound climate.

The data in Table 4-12 indicate that the dozer, crusher, and transfer equipment are the principal coal handling noise sources for sounds reaching Thermopyle. Noise control can be applied to these items to reduce sounds in an attempt to maintain the present L_{dn}.

The dozer produces the highest noise levels and is the most difficult to quiet. The engine exhaust noise can be reduced by an improved muffler. Cooling system improvements plus an enclosure around the engine and transmission reduces sound level emissions also. Some work by EPA has shown that dozer noise reductions are feasible.

Both the crusher and the transfer equipment noise can be reduced by use of enclosures. While this equipment may have a roof to limit dust emissions, the sides and bottom of conveyors are open, allowing noise to be emitted without constraint. Enclosing the sides and bottom as well as the top with sound attenuating and absorbing treatment should reduce emitted sound by 10 dB, which is all that would be needed.

4.2.5.6 Health and Safety

Generic effects of converting power plants and major fuel burning installations to coal are discussed in the programmatic EIS (DOE, 1979a) and in the Draft Northeast Regional EIS (DOE, 1981). The Mt. Tom conversion will comply with OSHA standards and with requirements of the Clean Water Act and the Clean Air Act through an NPDES permit, the DCO, and the SIP. Impacts to health and safety should therefore be minimal. (See also Section 2.7 and Appendix A of this EIS.)

4.2.5.7 Costs

Capital Costs

As stated in the MOU, all conversion costs (net of taxes and cost of capital) will be recovered by means of an Oil Conservation Adjustment (OCA). The price of oil at the moment coal is first burned at Mt. Tom is established as a cost baseline. The cost of conversion is then to be recovered by a charge equal to two-thirds of the fuel-cost savings resulting from the difference between coal prices and the established oil price. This rate will be applied to retail, wholesale, and special contract customers of the company and its affiliates in Massachusetts and Connecticut. However, the rates will not be less than that necessary to pay the maximum potential estimated costs of conversion in 36 months. If the company receives any Federal or state grants as a result of the conversion, these amounts will be used to reduce the conversion cost and, hence, the OCA. The total coal conversion cost could range as high as $35 million.

One benefit of the OCA is that the ratepayers are not exposed to escalating oil prices. They can benefit from cheaper electricity beginning at the time coal is first burned.

Financing under the OCA concept does not lend itself to traditional annualized capital cost calculations. The actual cost of conversion will not be paid over the plant's lifetime at a fixed interest rate but will be financed by the OCA in less than 42 months (the original MOU timetable). The cost of coal conversion is presently estimated by NUSCO to be $35 million (Table 4-14). NU estimates the cost of oil at $34.75 per barrel and a coal cost of $61.00 per ton (in January 1982). The benefits to the wholesale customers resulting from the conversion are indicated on Tables 4-15 and 4-16 for the year 1982. These figures indicate an electricity rate reduction of $9.168 million for 1982. This includes a contribution of $18.336 million to the utility from the OCA for capital cost expenditures, or $1.528 million per month. At this average rate it would take 20.8 months for the utility to recover the $31.8 million required for the conversion.

TABLE 4-14

HOLYOKE WATER POWER COMPANY CONVERSION TO COAL AT MT. TOM CAPITAL COST AND CASH FLOWS

(in thousands)

CAPITAL COSTS	
Coal Handling Equipment	$ 6,932
Boiler Modifications	1,405
Precipitators	10,819
Ash Handling Equipment	3,641
Ash Disposal/Water Treatment Facility	12,203
Total	$35,000

These costs are estimates presented to FERC by Luis B. Ellis (1980, President, Northeast Utilities). In testimony presented by Mr. Ellis, approximately $14 million would be expended in short-term debts for initial operation and maintenance costs. Estimates of costs and cost savings on Federal and state income taxes (Table 4-17) indicate that $31,800,000 will be required in revenue from the OCA funding.

Operating and Maintenance Costs

Operating and maintenance costs for a coal fired unit are greater than for oil firing because of the greater number of personnel, increased costs of the coal handling, ash handling and disposal systems, and increased maintenance on the boilers. It is estimated that operating and maintenance costs for burning coal are approximately 20 to 25 percent higher than for oil. The oil and low-sulfur coal operating and maintenance costs (1981 dollars) are listed below:

	Fixed Mills/kwhr	Variable Mills/kwhr
Oil Firing	1.48	----
Coal Firing	1.50 - 1.89	0.39

NUSCO has indicated that no significant differences in future employment are expected over the previous coal burning operation; only about 18 additional operational personnel are required (NUSCO, 1981).

TABLE 4-15

HOLYOKE WATER POWER COMPANY AND NORTHEAST UTILITY COMPANIES
REVENUE COMPARISONS - 1981 AND 1982
MT. TOM ENERGY SALES TO NEPCO (37.8% ENTITLEMENT)
(in thousands)

		Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
5	1981 Oil-Fired Generation													
6	Kilowatt-hours	25,250	25,250	25,250	25,250	25,250	25,250	25,250	25,250	25,250	25,250	25,250	25,250	303,000
7	Fuel Cost	$ 1,057	$ 1,056	$ 1,057	$ 1,056	$ 1,057	$ 1,056	$ 1,057	$ 1,056	$ 1,057	$ 1,056	$ 1,057	$ 1,056	$ 12,678
8	Other	261	261	261	261	261	261	261	261	261	261	261	261	3,132
9	Total	1,318	1,317	1,318	1,317	1,318	1,317	1,318	1,317	1,318	1,317	1,318	1,317	15,810
10	Fuel Cost	$ 1,057	$ 1,056	$ 1,057	$ 1,056	$ 1,057	$ 1,056	$ 1,057	$ 1,056	$ 1,057	$ 1,056	$ 1,057	$ 1,056	$ 12,678
11	Other	261	261	261	261	261	261	261	261	261	261	261	261	3,132
12	Total	1,318	1,317	1,318	1,317	1,318	1,317	1,318	1,317	1,318	1,317	1,318	1,317	15,810
13	Summary													
14	Difference	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Percent Difference	0	0	0	0	0	0	0	0	0	0	0	0	0
16	1982													
17	Kilowatt-hours	30,008	30,009	30,008	30,009	30,008	30,009	30,008	30,009	30,008	30,009	30,008	30,009	360,102
18	Oil-Fired Generation													
19	Oil Fuel Cost	$ 1,586	$ 1,587	$ 1,587	$ 1,587	$ 1,587	$ 1,587	$ 1,587	$ 1,587	$ 1,587	$ 1,587	$ 1,587	$ 1,587	$ 19,043
20	Other	323	324	323	324	324	324	324	324	324	324	324	324	3,886
21	Total	1,909	1,911	1,910	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	22,929
22	Coal-Fired Generation													
23	Coal Fuel Cost	$ 720	$ 721	$ 721	$ 721	$ 721	$ 721	$ 721	$ 721	$ 721	$ 721	$ 721	$ 721	$ 8,651
24	Other	323	324	323	324	324	324	324	324	324	324	324	324	3,886
25	OCA Revenues	577	577	577	577	577	577	577	577	578	578	578	578	6,928
26	Total	1,620	1,622	1,621	1,622	1,622	1,622	1,622	1,622	1,623	1,623	1,623	1,623	19,465
27	Summary													
28	Difference (Reduction)	$ (289)	$ (289)	$ (289)	$ (289)	$ (289)	$ (289)	$ (289)	$ (289)	$ (288)	$ (285)	$ (288)	$ (288)	(3,464)
29	Percent Difference (Reduction)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)

TABLE 4-16

ESTIMATES OF TRANSACTIONS AND REVENUES UNDER INITIAL RATE SCHEDULE FILED FOR NUG&T COMPANIES OIL CONSERVATION ADJUSTMENT - 1982

(in thousands)

5		Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
6	**Mt. Tom Kilowatt-hours**													
7	CL&P	30,255	29,840	27,242	26,050	23,971	24,968	25,498	25,947	25,945	25,025	25,915	28,643	319,299
8	HELCO	15,178	14,613	13,881	13,280	12,656	12,922	13,960	13,596	12,836	12,904	12,795	14,123	162,744
9	WMECO	9,613	9,205	8,695	8,091	7,263	7,276	7,542	7,921	7,877	7,490	7,991	9,098	98,062
10	HWP	1,170	1,135	1,121	1,027	941	969	974	1,162	1,079	1,131	1,095	1,091	12,895
11	Total	56,216	54,793	50,939	48,448	44,831	46,135	47,974	48,626	47,737	46,550	47,796	52,955	593,000
12	**Oil-Fired Generation**													
13	Fuel Cost													
14	CL&P	$ 1,597	$ 1,575	$ 1,438	$ 1,375	$ 1,265	$ 1,318	$ 1,346	$ 1,370	$ 1,370	$ 1,321	$ 1,368	$ 1,512	$ 16,855
15	HELCO	801	771	733	701	668	682	737	718	677	681	675	745	8,589
16	WMECO	507	486	459	427	383	384	398	418	416	395	422	480	5,175
17	HWP	62	60	59	54	50	51	51	61	57	60	58	58	681
18	Total	2,967	2,892	2,689	2,557	2,366	2,435	2,532	2,567	2,520	2,457	2,523	2,795	31,300
19	**Coal-Fired Generation**													
20	Fuel Cost and OCA Revenues													
21	CL&P Fuel Cost	724	714	651	622	572	597	610	621	621	598	620	685	7,635
22	OCA Revenues	582	574	524	501	461	481	491	499	499	482	499	551	6,144
23	Total	1,306	1,288	1,175	1,123	1,033	1,078	1,101	1,120	1,120	1,080	1,119	1,236	13,779
24	HELCO Fuel Cost	363	349	332	318	303	309	334	325	307	309	306	338	3,893
25	OCA Revenues	292	281	267	256	244	249	269	262	247	248	246	272	3,133
26	Total	655	630	599	574	547	558	603	587	554	557	552	610	7,026
27	WMECO Fuel Cost	230	220	208	194	174	174	180	189	188	179	191	218	2,345
28	OCA Revenues	185	177	167	156	140	140	145	152	152	144	154	175	1,887
29	Total	415	397	375	350	314	314	325	341	340	323	345	393	4,232
30	HWP Fuel Cost	28	27	27	25	23	23	23	28	26	27	26	26	309
31	OCA Revenues	23	22	22	20	18	19	19	22	21	22	21	21	250
32	Total	51	49	49	45	41	42	42	50	47	49	47	47	559
33	TOTAL Fuel Cost	1,345	1,310	1,218	1,159	1,072	1,103	1,147	1,163	1,142	1,113	1,143	1,267	14,182
34	OCA	1,082	1,054	980	933	863	889	924	935	919	896	920	1,019	11,414
35	TOTAL	2,427	2,364	2,198	2,092	1,935	1,992	2,071	2,098	2,061	2,009	2,063	2,286	25,596
36	**Summary**													
37	Difference (Reduction)	(540)	(528)	(491)	(465)	(431)	(443)	(461)	(469)	(459)	(448)	(460)	(509)	(5,704)
38	Percent Difference (Reduction)	(18.20)	(18.26)	(18.26)	(18.19)	(18.22)	(18.19)	(18.21)	(18.27)	(18.21)	(18.23)	(18.23)	(18.21)	(18.22)

NUG&T - Northeast Utilities Generating & Transmission Agreement.

TABLE 4-17

ESTIMATE OF REVENUE REQUIREMENTS FOR COAL CONVERSION OF MT. TOM
(in Thousands)

Cost of Conversion	$35,000
Carrying Costs[a]	4,672
Federal and Massachusetts Income Taxes	16,260
Tax Payments	
Tax Recoveries	
Tax Depreciation Deduction	(17,896)
Investment Tax Credits	(3,850)
Interest Expense Deduction	(2,386)
Revenue Requirements	$31,800

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[a] Carrying costs are calculated at a 12 percent annual interest rate applied to the average outstanding balance of funds for the cost of conversion.

5.0 OTHER NEPA REQUIREMENTS

5.1 UNAVOIDABLE ADVERSE IMPACTS

5.1.1 Air Quality

Conversion to low-sulfur coal as the major fuel at the Mt. Tom generating station under the planned action will have three unavoidable adverse impacts.

1) The planned action will cause an increase in the stack emission rate of particulate matter over the period of the DCO. This will result in a slight degradation of the air quality during this period only. It is not expected to result in any long-term adverse impacts on air quality.

2) The planned action will allow higher short-term (24-hour) SO_2 emission rates. This will result in an occasional slight degradation of the local air quality. No significant, or even measurable, adverse environmental impacts are expected to result from this.

3) There will be an increase in fugitive dust due to the conversion. As described in Section 4.2.3, the quantity of fugitive dust expected is small and while there will be a very slight degradation of the air quality in the immediate vicinity of the plant, it is expected to be well below the levels of significance.

The change in short-term sulfur dioxide emissions is not expected to change the facility's impact on the development of acid rain down wind of the facility.

5.1.2 Land Use

Several acres of land will be required for disposal of ash and wastewater. Under the conversion as discussed in Sections 1.5 and 2.3, most of this land has been previously disturbed by earlier coal burning activities. If onsite storage of fly ash were continued for the life of the plant, some 15 acres of prime farmland would be converted to waste storage. Alternatively, if a market is not found for the fly ash, some offsite area would be acquired for ash disposal if existing disposal sites are not available.

5.1.3 Water Quality

As dictated by the MOU, the utility is conducting monthly ground water quality monitoring at the Mt. Tom generating station. If at any time during the year of monitoring infiltration from the basins is found to be causing degradation of the ground water, the utility will take appropriate corrective or remedial actions.

The conversion is expected to have minimal impact on surface water quality beyond that of the oil burning configuration. The conversion will require all discharges to be under the strict limitations of the NPDES permit.

5.2 RELATIONSHIP BETWEEN SHORT-TERM USES OF MAN'S ENVIRONMENT AND MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY

5.2.1 Beneficial Aspects of Short-Term Use of the Environment

The principal benefit of utilizing coal as the primary energy source in the boiler at the Mt. Tom generating station is the potential savings of 1.5 million barrels of imported oil per year; this savings will be realized if the Mt. Tom generating station operates at 80 percent capacity. This savings contributes to the reduction of U.S. dependence on foreign oil supplies. Since coal is a less expensive fuel than oil, an additional benefit of lower electric rates will be realized by consumers.

5.2.2 Adverse Impacts on Long-Term Productivity of the Environment

The plant will consume 0.384 million tons of coal per year. The states of Pennsylvania and West Virginia, for example, from which the coal may come produce approximately 200 million tons per year from surface and underground mines. The incremental impact of the Mt. Tom station requirements on this production is minimal.

If onsite waste storage areas were utilized for fly ash disposal for the life of the plant, impacts would be primarily to acreage that has been previously disturbed. It is possible that 15 acres of prime farmland could be removed from productivity for 10 to 15 years, depending on the life of the plant. This acreage would probably be used for fly ash storage. Studies indicate that fly ash, especially weathered ash, may be beneficial to soils (GAI, 1979). It is probable, therefore, that restoring these lands to useful agricultural purposes could be accomplished within a few years after discontinuance of use of the areas for fly ash storage.

Construction of wastewater and ash storage ponds as well as the coal storage and coal runoff areas will decrease Connecticut River floodplain storage capacity by 103 acre-feet. The utility is committed to providing 300 acre-feet of compensatory storage in the Northfield Mountain pumped storage facility about 30 miles upstream of the site.

5.3 IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

Issuance of an NOE would cause an irreversible commitment of 384,000 tons of coal per year for fuel at the plant. The coal would replace as much as 1.5 million barrels of oil per year which would otherwise be committed as fuel. Over a 20-year life of the project the plant would require more than 7.6 millon tons of coal, but would provide a savings of as much as 30 million barrels of oil. Partially offsetting this estimated fuel savings is an increased need for refined oil products for coal transportation. This increased fuel demand would be small in comparison to potential savings in fuel oil. Also, the fuel needed for the transportation of coal is less than that needed for oil.

Conversion to coal capability required a minor commitment of labor for construction of new/upgraded equipment and for operation and generation.

There has been a minor commitment of steel, concrete, and other materials for construction of new coal handling equipment/facilities. Most of this material would be recoverable, however, at the end of the project lifetime.

The only other resource commitment would be short-term loss of productivity and habitat on lands used for waste disposal.

5.4 CONFLICTS BETWEEN THE PROPOSED ACTION AND THE OBJECTIVES OF FEDERAL, REGIONAL, STATE, AND LOCAL PLANS

Because the Mt. Tom generating station was originally designed to burn coal the necessary land and much of the equipment are already available. The major effects of the reconversion are incremental, resulting from the change in fuel use.

All land is already zoned for use by an electrical generating facility, and much of the property has been previously used for coal and ash storage. There are, therefore, no expected conflicts with existing land use plans.

Emissions will be in accordance with EPA and MOU requirements. Until February 1984, emissions must be in accordance with the DCO; and following that period, the SIP.

Any discharges from the plant will be in accordance with the NPDES permit.

Possible conflicts exist with the potential use of 15 acres of prime farmland which might be needed for ash storage. There is also a conflict with requirements of the DEQE with regard to development on the floodplain. As discussed in Section 3.2.1, increases in flood levels as a result of planned development would not be measurable. The utility has also agreed to providing compensatory flood storage of 300 acre-feet upstream of the site to offset the 103 acre-feet of storage to be lost as a result of required construction.

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APPENDIX A

HEALTH EFFECTS OF EXPOSURE TO AGENTS PRODUCED BY COAL COMBUSTION

Appendix A reproduces, in its entirety,
Appendix E from the Draft Northeast
Regional EIS (DOE/EIS-0083-D, October 1981),
as background for Section 2.7 of this EIS.

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APPENDIX E. HEALTH EFFECTS OF EXPOSURE TO AGENTS PRODUCED BY COAL COMBUSTION

E.1 SULFUR OXIDES AND PARTICULATES

The sulfur oxide and particulate complex produced during the combustion of sulfur-containing fossil fuels is the major component of air pollution released from coal-fired powerplants. In 1975, 62% of all sulfur oxide emissions in the U.S. came from coal-fired powerplants (MITRE Corporation 1978).

Historically, adverse health effects from sulfur dioxide pollution were associated with acute, high-exposure air pollution episodes that resulted in increased death and respiratory illness (Ferris 1978). Subsequent studies (Amdur 1957, 1959; Amdur and Underhill 1968, Alaire et al. 1972) indicated that sulfur dioxide by itself is not a potent pulmonary irritant and could not be the primary causative agent. The apparent reason for the low potency is that inhaled SO_2 is nearly completely absorbed in the upper airways and does not reach the lung. Sulfur dioxide penetrates into the lungs only when it is adsorbed onto the surface of respirable particulate matter (approximately 2 μ diameter or less).

There have been more studies of human health effects of sulfur oxides and particulates than of the other components of air pollution. Both short-term acute air pollution episodes and long-term increases in air pollution levels (such as those present in many major cities) have been shown to be associated with increased death rates. This increase most probably is attributable to elevated mortality in individuals already at high risk, such as the sick and the elderly. Numerous studies of the health effects of long-term high exposures have revealed associations with chronic respiratory disease in adults (both higher incidence of new cases and increased symptoms in existing cases), changes in lung function in adults and children, and acute lower respiratory tract illnesses in both adults and children (National Academy of Sciences 1973; American Thoracic Society 1978; Ferris 1978; Holland et al. 1979; Shy 1979). Studies of animals and human populations (McJilton et al. 1973; Amdur and Corn 1963; Amdur 1971; USEPA 1974) suggest that the primary causative agents are oxidation products of sulfur dioxide, namely sulfuric acid and particulate sulfates, possibly acting synergistically with sulfur dioxide and other pollutants such as nitrates, particles, and ozone. Sulfur dioxide, smoke, and suspended particulates and, more recently, suspended sulfates have been used as indices of pollution and there is as yet no firm evidence as to which substance or substances are the causative agents.

Experiments in which volunteers were exposed to sulfuric acid have had various results. Observed effects include transient cough, constriction of bronchial airways, increased lung resistance, changes in the flow of air through specific passageways, and a decrease in clearance between cilia (the hair-like projections that help clear the lungs) as a result of increased mucus production in the lungs. These effects were observed at exposure concentrations ranging from 100 μg/m^3 to 39,000 μg/m^3 (Morrow et al. 1980; Sim and Pattle 1957; Lippmann 1980) On the other hand, in several other studies, no adverse effects were reported at levels up to 1000 μg/m^3 (Sackner et al. 1977; Sackner et al. 1978; Newhouse et al. 1978).

The National Air Surveillance Network (NASN) has collected data on sulfate levels in the United States. NASN estimated an annual average global background level of 1-2 μg/m^3 (USEPA 1975). There is a 24-state region in the northeastern U.S. that has consistently higher levels of pollutants than the rest of the country. In 1972 urban air in this area had an annual average sulfate level of 13.6 μg/m^3, with 10.2 μg/m^3 for nonurban air. The annual average of urban air in the rest of the country was 7.9 μg/m^3, with 4.4 μg/m^3 for nonurban air.

Human health effects of sulfates have been reported in experimental and epidemiological studies. The major epidemiological studies have been done by the Community Health and Environment Surveillance System (CHESS) of the Environmental Protection Agency. *In one CHESS study it was* found that a 10% increase in the rate of asthma attacks occurred when the minimum temperature was above 50°F and the suspended sulfate (SS) level was greater than 10 μg/m^3. The threshold level was estimated to be 12 μg/m^3 of SS when the minimum temperature was between 70° and 50°F (Finklea et al. 1974a). In another CHESS report, the threshold level for effects was estimated to be 1.4 μg/m^3 at temperatures greater than 50°F (Finklea et al. 1974b).

Cohen et al. (1972) studied asthmatics in West Virginia who lived near a coal-fired powerplant. Although no single pollutant could be determined to be the prime cause of asthma attacks, "...suspended sulfate levels showed the strongest association with attack rate after the effects of temperature were removed." A sulfate level of 20 μg/m^3 was used as the concentration defining days of high and low pollution levels.

The best judgement of the point at which suspended sulfates (SS) result in cardiopulmonary symptoms in the elderly was estimated to be 6 μg/m³ (24-hour average) (Stebbings and Hayes 1976). An increase in chronic bronchitis was noted in adults exposed to 4-7 years of 90-95 μg/m³ of SO_2, 15 μg/m³ of SS, and 60 μg/m³ of TSP. In another study an increase was found in acute lower respiratory disease in children exposed to three or more years of 177 μg/m³ of SO_2, 65 μg/m³ of TSP, and 7 μg/m³ of SS (USEPA 1974).

Sulfate levels of 9-15 μg/m³ were estimated to be the points at which increased acute respiratory disease and chronic bronchitis occur. Concentrations of 6-10 μg/m³ of SS were estimated to aggravate asthma (USEPA 1975; Colucci 1976).

Both SO_2 and total suspended particulates (TSP) are referred to as criteria pollutants because there are National Ambient Air Quality Standards (NAAQS) for them. The pollution control technologies employed in the 42 Northeast Region powerplants would be engineered to comply with these standards. At present, there are no ambient air quality standards for SO_2 transformation products such as sulfuric acid and sulfates, or for the respirable fraction of the TSP that serves to transport volatile materials to sites deep within the lung.

E.2 NITROGEN OXIDES AND PHOTOCHEMICAL OXIDANTS

The principal man-made sources of nitrogen oxides are coal, oil, natural gas, and motor vehicle fuel combustion. High levels of NO_2 (above 282 mg/m³) can be lethal (National Academy of Sciences 1977). Nonurban regions average 8 μ/m³ NO_2 and 2 μg/m³ NO (USEPA 1971), whereas in urban areas, concentrations of nitrogen oxide are 10-100 times greater. Ten percent of the cities in the United States with populations less than 50,000 and 54% of those with populations between 50,000 and 500,000 have a yearly average nitrogen dioxide concentration equal to or exceeding 0.06 ppm (113 μg/m³), the lower limit at which health effects were noted in a community study in Chattanooga (Shy et al. 1970a, 1970b); 85% of the cities in the 7,500,000 population class exceed this yearly average. Meeting the current Ambient Air Quality Standard for nitrogen oxide of 100 μg/m³ expressed as the yearly arithmetic mean concentration would be more difficult in the large population concentrations in the Northeast.

Tables E.1 and E.2 are summaries of the results of laboratory studies and human population studies, respectively. Information on chronic nitrogen dioxide poisoning is extremely scarce because, (1) no response is observed until a critical concentration is reached, (2) damage develops slowly, and (3) nitrogen dioxide usually is associated with other pollutants. According to the intensity and duration of exposure, respiratory illness ranges from slight irritation to burning and pain in the throat and chest to violent coughing and shortness of breath (Waldbott 1973).

Photochemical oxidants are formed in the atmosphere from nitrogen oxides and hydrocarbons. Ozone is the largest component, but compounds such as peroxyacetyl nitrate (PAN), acrolein, peroxybenzoyl nitrates (PB_2N) and aldehydes probably are responsible for the acute irritative effects on the eyes, nose, and throat associated with photochemical air pollution. Efforts to identify excess mortality associated with increased levels of photochemical air pollution have not been successful.

On the basis of studies by Renzetti and Gobran (1957), Richardson and Middleton (1958), and Hammer et al. (1974), there is evidence of nose, throat and eye irritation in the range of 200-294 μg/m³. Cough and chest discomfort increased markedly when a level of 588 μg/m³ was reached. Motley et al. (1959) reported decreased lung function among patients with chronic respiratory disease exposed to unfiltered Los Angeles air relative to filtered air (this effect was reversible). The levels of exposure were estimated to be in the range of 200-294 μg/m³. Bates and Huzucha (1973) observed a reduction in lung function among healthy subjects at an ozone level of 725 μg/m³, and an enhancement of this effect in the presence of SO_2 at 969 μg/m³.

E.3 RESPIRABLE PARTICULATE MATTER

The U.S. Environmental Protection Aency (USEPA) was charged with completing a review of the Clean Air Act and promulgating revised standards by December 1980. The role of fine particles in development of human respiratory disease has elicited much response from both the public and the scientific community during EPA's period of comment solicitation. As a result of this public discussion, EPA has established a number of definitions and parameters that will almost certainly be incorporated into any revised particulate matter standard (Miller et al. 1979).

The common unit of size in most air quality literature is the aerodynamic diameter, defined as the "diameter of a unit density sphere having the same settling velocity as the particle under consideration" (Morgan and Turner 1973, p. 327). Particulates derived from fossil-fuel combustion may be crystalline or amorphous forms, fibers, spheres, or aggregate meshes (Holland et al. 1979, p. 534) on which transformation products, toxic elements, and organic molecules can adsorb.

Table E.1. Summary Laboratory Studies of Human Beings Exposed to NO_2

Concentration mg/m^3 (ppm)	Duration of Exposure	Effects	Reference[a]
0.200 (0.11)	1 hr	3/20 Asthma Inc. Raw 13/20 Increased sensitivity Carbacol.	Orehek et al. (1976)
0.564 (0.3) (added to O_3 exposure)	2 hr	No increased response in "reactive" subjects	Hackney et al. (1975)
1.316-1.880 (0.7-1.0) (plus other components)	Not specified (until pulse 150/minute)	No significant change in reaction time or cardiorespiratory work efficiency in healthy subjects.	Holland et al. (1968)
<2.820 (<1.5)	0.25 hr	No change R_{aw} healthy subjects	Nieding et al. (1973)

From Ferris (1978).

[a] References to studies cited here are in the source, and are omitted in this report.

Table E.2. Summary of Studies of Effects of NO_2[a] on Human Populations

Concentration mg/m^3 (ppm)[b]			
Mean	90th Percentile	Effects	Reference[c]
0.15-0.28 (0.08-0.15)	0.28-0.94 (0.15-0.50)	Slight increase in respiratory illness and slight decrease in pulmonary function.	Shy (1973)
Same as above		Slight increase in bronchitis morbidity. (No effect on croup, pneumonia or hospitalizations.)	Pearlman et al. (1971)
0.096 vs 0.043 (0.051 vs 0.023)	0.188 vs 0.113 (0.10 vs 0.06)	No effect on healthy nonsmoking adults.	Cohen et al. (1972)
0.103 (0.055)	Maximum 0.263-0.564 (0.140-0.3)	Questionable small increase in respiratory symptoms; no difference in pulmonary function.	Speizer et al. (1973a, 1973b)

From Ferris (1978).

[a] In all instances exposures were mixed and other components, such as sulfur oxides and particulates, also tended to be higher than in "control" area.

[b] Values reflect annual averages or distributions.

[c] References to studies cited here are in the source, and are omitted here.

Particles greater than 2 μ (aerodynamic diameter) arise from mechanical abrasive forces and have been classified as "coarse" (Whitby and Cantrell 1976). These include materials such as sea spray and windblown dust. Most particles less than 2 μ are created during condensation of either hot or cold super-saturated vapors and are classified as "fine". These particles are produced largely during industrial processes (see Fig. E.1). Characteristics of physical deposition in biological systems also support a size discrimination between "fine" and "coarse" at approximately 2 μ (Lippmann 1977; Lippmann et al. 1979; Palmes and Lippmann 1977; Altshuler et al. 1957, 1967) (Fig. E.2); linear measurements are used for diameters <0.5 μ since diffusional displacement is the dominant deposition mechanism for particles of this size (i.e., neither density nor shape are significant parameters for very fine particles) (Lippmann 1977). At diameters less than 2.5 μ, total deposition in the alveoli (the sacs in the lungs) ranges between 15 and 25%. Approximately 45% deposition occurs during mouth breathing. Since alveoli have no cilia and comprise the gas-exchange surface of the deep lung, any material preferentially deposited there should be studied carefully. This is particularly true of particles less than 0.5 μ in linear diameter, because these are transported throughout body systems by diffusion and circulation. As a result of these findings, USEPA's Health Effects and Environmental Science Research Laboratories are recommending to the Office of Air Quality Planning and Standards a cutoff point of 2.5 μ aerodynamic diameter for setting a size-specific standard.

Most fine particles readily take up and retain moisture, and rapidly gain size and mass during passage through the humid atmosphere of respiratory airways. All larger particles, regardless of origin, often are mechanically removed from the airstream by sneezing, nose blowing, etc. (National Research Council 1979, p. 109). Once past the nasal opening, particles less than 1.0 μ may settle out on nasal hairs and bends of the conchae. Mucus transported by cilial action from these inner regions to the outer regions of the nose may then be expelled mechanically by sneezing or nose blowing. Diffusion also can occur on the conchae for particles less than 0.1 μ (National Research Council 1979, p. 109). Particles captured in mucus in the throat are quickly swallowed and pass through the GI tract, from which they are eventually eliminated. Deposition on the larynx ("voice box") can result from breathing through either the nose or mouth. Under normal conditions, particles can be captured in mucus, swallowed and eliminated. However, this may not be true of exposure from some occupational or domestic sources (particularly cigarette smoke) (National Research Council 1979, p. 109). Such particles may interact synergistically with other non-occupational or non-cigarette related emissions.

In the smaller-diameter respiratory airways, up to 40% of the particles are deposited by diffusion and sedimentation. In normal tissue, inert and insoluble particles can be cleared by cilia or mucus transport in one day; soluble particles are removed more quickly (Albert et al. 1969; Yeates et al. 1973). In the alveolar region, soluble particles may pass through the outer membrane within minutes. Half-time clearances for insoluble particles in this zone may be on the order of months or years, since alveoli do not contain cilia or mucus. It is to be expected that fine particles are preferentially deposited in this region, where the deposition fraction can equal 65% (Task Group on Lung Dynamics 1966). Although the relative importance of removal mechanisms in the alveoli is presently unclear, there is substantial agreement that deposition in these tissues has tremendous potential for damage.

Several of the toxic elements released to the atmosphere during coal combustion are associated with small-particle emissions. It is thought that these elements and/or their compounds volatilize during combustion and condense or adsorb onto the fine particles that are not captured by precipitators or flue-gas desulfurizers (Natusch et al. 1974). Those elements in airborne fly ash that exhibit the most pronounced trends of increasing concentration with decreasing diameter are listed in Table E.3 (Davison et al. 1974). Similar inverse relationships between fly ash particle size and element concentration have been noted by Lee and von Lehmden (1973) and Toca (1972). Other elements found in fly ash include iron, manganese, vanadium, silicon, magnesium, carbon, beryllium, and aluminum; these exhibit only limited concentration trends (Davison et al. 1974)

Some compounds found concentrated on the surfaces of fine particles are not only known to be toxic, but also are suspected carcinogens. Particulate polycyclic organic matter (POM) and compounds of the elements lead, cadmium, selenium, arsenic, nickel, and chromium fall into this latter category (Natusch 1978). The particle-size dependencies of arsenic, nickel, cadmium, and sulfur concentrations are clearly illustrated in Fig. E.3. High concentrations of all elements listed above, particularly sulfur, are found in a 300-angstrom-thick shell (an angstrom is one ten-billionth of a meter) on fly ash surfaces (Natusch 1978). This ready availability of toxic elements and large surface area provided by fine particles allows intimate contact with body fluids and alveolar tissues (Natusch 1978). As a result, there is legitimate concern that the detectable health effects of exposure may alter all bodily systems rather than respiratory systems alone (U.S. Office of Technology Assessment 1979, p. 205).

Approximately 50% of the total sulfur released is associated with the smallest size fraction. Most of this sulfur is thought to be in the form of sulfuric acid mists or metallic sulfate compounds. Some health analysts now consider these transformation compounds to be at least partly responsible for the hazard presented by inhaled gaseous sulfur oxides (Natusch 1978). Other contaminants include NO_2 and nitrate and hydrocarbon aerosols.

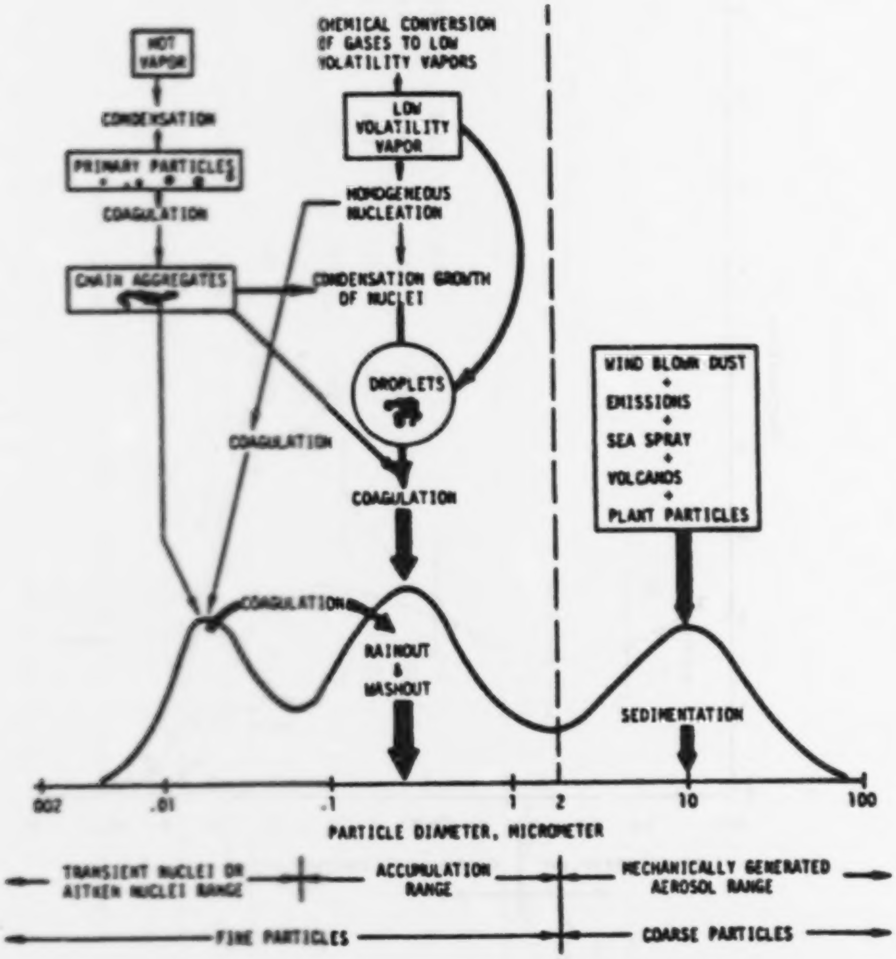
HOT VAPOR
CONDENSATION
PRIMARY PARTICLES
COAGULATION
CHAIN AGGREGATES
CHEMICAL CONVERSION OF GASES TO LOW VOLATILITY VAPORS
LOW VOLATILITY VAPOR
HOMOGENEOUS NUCLEATION
CONDENSATION GROWTH OF NUCLEI
DROPLETS
COAGULATION
COAGULATION
COAGULATION
WIND BLOWN DUST
+
EMISSIONS
+
SEA SPRAY
+
VOLCANOS
+
PLANT PARTICLES
RAINOUT & WASHOUT
SEDIMENTATION
.002
.01
.1
1
2
10
100
PARTICLE DIAMETER, MICROMETER
TRANSIENT NUCLEI OR AITKEN NUCLEI RANGE
ACCUMULATION RANGE
MECHANICALLY GENERATED AEROSOL RANGE
FINE PARTICLES
COARSE PARTICLES

Fig. E.1. Schematic of an Atmospheric Aerosol Surface Area Distribution Showing Principal Modes, Main Sources of Mass for Each Mode, and the Principal Processes Involved in Inserting Mass in Each Mode and the Principal Removal Mechanisms. Reproduced from Whitby and Cantrell (1976), Fig. 2, copyright 1976, IEEE.

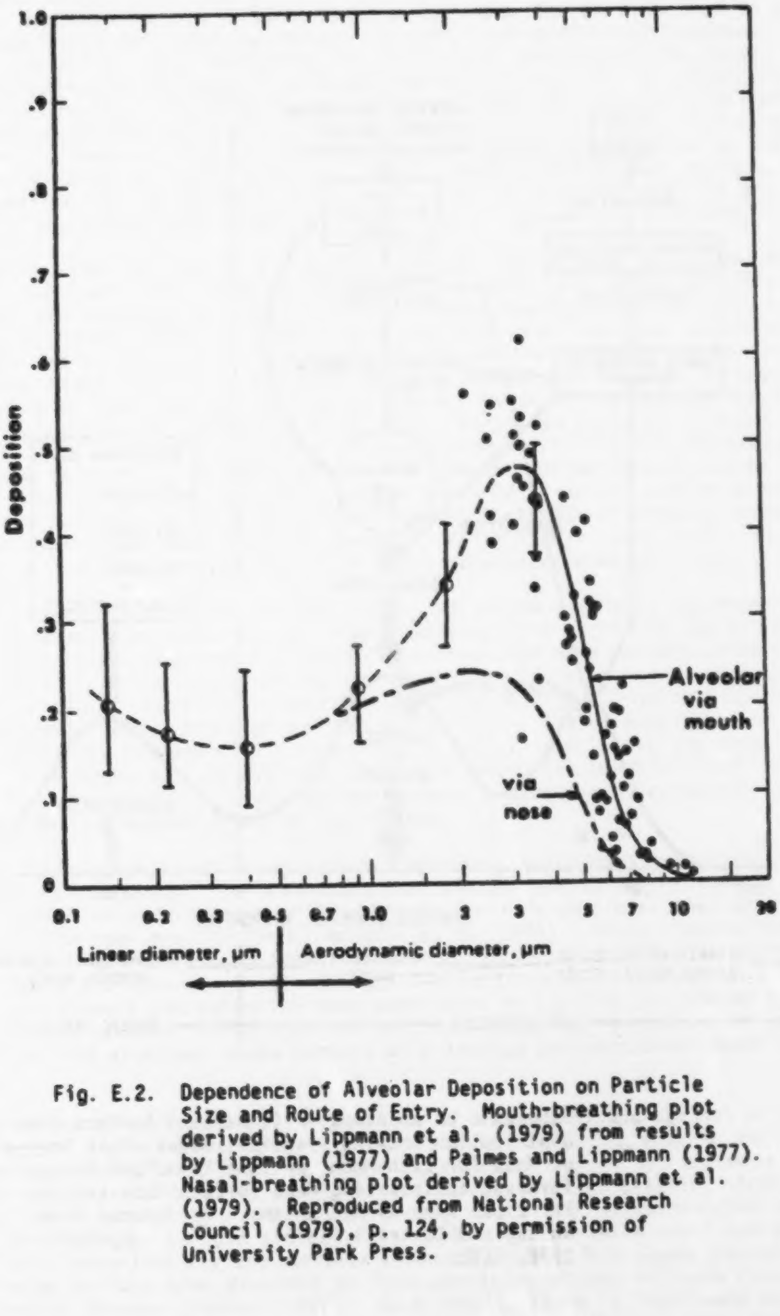

Fig. E.2. Dependence of Alveolar Deposition on Particle Size and Route of Entry. Mouth-breathing plot derived by Lippmann et al. (1979) from results by Lippmann (1977) and Palmes and Lippmann (1977). Nasal-breathing plot derived by Lippmann et al. (1979). Reproduced from National Research Council (1979), p. 124, by permission of University Park Press.

Table E.3. Concentrations of Toxic Elements in Airborne Fly Ash

Particle Diameter (μm)	Elemental Concentration (μg)									
	Lead[a]	Thallium[b]	Antimony[b]	Cadmium[a]	Selenium[a]	Arsenic[a]	Nickel[a]	Chromium[a]	Zinc[b]	Sulfur[c] (wt. %)
> 11.3	1100	29	17	13	13	680	460	740	8100	8.3
7.3-11.3	1200	40	27	15	11	800	400	290	9000	-
4.7-7.3	1500	62	34	18	16	1000	440	460	6600	7.9
3.3-4.7	1550	67	34	22	16	900	540	470	3800	-
2.1-3.3	1500	65	37	26	19	1200	900	1500	15000	25.0
1.1-2.1	1600	76	53	35	59	1700	1600	3300	13000	-
0.65-1.1	-	-	-	-	-	-	-	-	-	48.8

Adapted from Davison et al. (1974), Table 1, p. 1109.

[a] Spark source mass spectrometry.

[b] DC arc emission spectrometry.

[c] X-ray fluorescence spectrometry.

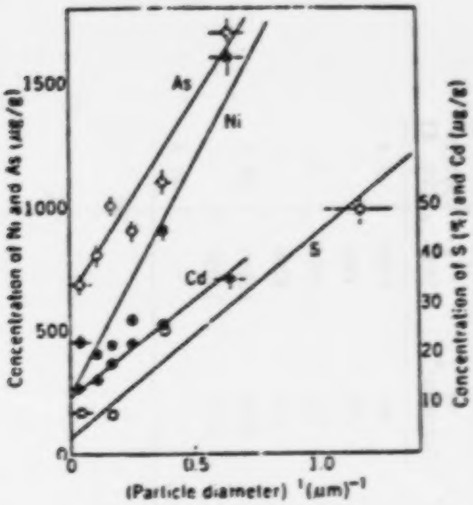

Fig. E.3. Dependence of the Average Concentrations of Arsenic, Nickel, Cadmium, and Sulfur on Airborne Particle Size in Coal Fly Ash. From Natusch et al. (1974). Copyright 1974 by the American Association for The Advancement of Science.

Similar assessments of the form and size distribution of particles from oil-fired plants have not been published as of this writing. Particulates derived from oil combustion are known to be highly porous in contrast to the smooth, aluminosilicate spheres common to coal combustion (Natusch 1978; McCrone and Delly 1973). Short-range transport (less than 8 km, or 5 mi) and particle-size distributions of particles from oil combustion are thought to be similar to those determined for coal combustion releases (Natusch 1978). However, the total quantity of particulate release from oil-fired facilities typically is 50 times less than that from a similar plant burning only coal (Natusch 1978).

Due to their small size and resulting slow rate of sedimentation (less than 10^{-2} cm/sec; National Research Council 1979, p. 33), fine particles behave as gases and may undergo long-range transport prior to washout or settling. Recent fallout samples collected in a forest of East Tennessee suggest that deposition of small-diameter particles containing lead, sulfates, cadmium, and zinc is a result of regional transport (Lindberg et al. 1979). Lindberg et al. (1979) discovered that lead and sulfate deposits were elemental and transformation products of combustion, while cadmium and zinc originated from small-particle combustion and large-particle dispersion (see Table E.4). These products of long-range transport exhibit the same concentration patterns of toxic elements on fine particles that were noted by Davison et al. (1974) and Natusch (1978).

Studies of fine particulate exposure in healthy and asthmatic individuals have been performed with inert dusts and powders such as calcium carbonate (chalk). Functional changes, i.e., airway flow resistance, gas trapping, and abnormal mixing of air in the lungs have been observed after brief inhalation of particles ≤ 1 μ in diameter (Dubois and Dautrebande 1958; Lovejoy et al. 1961). These changes may be caused by edema (retention of fluid in tissues) excessive secretion of mucus, or constriction of smooth muscle, trachea, or bronchii (Amdur and Underhill 1968). The exact mechanism is unknown. The additional alteration of impaired gas exchange also has been noted (Lovejoy et al. 1961).

Studies of human populations have been confined largely to major, acute episodes where large numbers of people were stricken. The Donora, New York City, Meuse Valley and London episodes are notable. At the time of these incidents, both investigators and instrumentation were insensitive to the potential role played by respirable particles causing illness and death. Data being collected during a 10-year monitoring program initiated by the Harvard School of Public Health in six communities throughout the United States will clarify the potential links between respiration of fine particles and human health (Ember 1977). The best available evidence indicates that inhalation of fine particles probably is harmful.

Table E.4. Some "Available" Metal[a] and Sulfate Air Concentrations in Walker Branch Watershed (Roane County, TN) during Intensive Sampling Experiments

Experimental Period	Aerodynamic[b] Diameter (μ)	TSP	Cadmium	Lead	Zinc	Sulfate
W1	Total	45 μg/m³	0.12 ng/m³	92 ng/m³	3.5 ng/m³	11.8 μg/m³
	> 8.0	17%	18%	2%	14%	2%
	3.7	25	33	7	16	2
	1.2	12	18	8	19	3
	0.5	13	18	16	18	22
	< 0.5	32	13	67	35	71
W2	Total	64 μg/m³	0.24 ng/m³	170 ng/m³	7.4 ng/m³	18.0 μg/m³
	> 7.8	18%	6%	1%	8%	1%
	3.7	17	16	4	7	2
	1.2	12	23	8	11	8
	0.48	30	10	33	8	48
	< 0.48	24	44	53	66	42

Adapted from Lindberg et al. (1979).

[a] "Available" metal = distilled leachable plus dilute acid leachable.

[b] Assuming a 50% particle collection efficiency.

Since 1924, the use of electrostatic precipitators (ESPs) has been the most common method of controlling particulate releases from coal-fired boilers (Manhattan College Department Chemical Engineering (MCDCE) 1978, p. 45). This method has been highly successful in reducing emissions of large-diameter particles, but is less efficient at capturing fine ash. Even though fine particles are not the greatest mass released from coal-fired facilities, the portion that is ≤2.5 μ is considerable. Approximately 30% of the total release falls in this size class even with installation of ESP controls (Lee et al. 1975). The distribution of aerodynamic diameter and cumulative mass for emissions from one ESP-controlled Midwestern generating station is illustrated in Figure E.4. Such a distribution is considered common.

Wet scrubbers can effectively remove both gaseous and particulate pollutants from stack gases by inertial impaction, direct interception, diffusion, and condensation (MCDCE 1978, p. 79). Collection of SO_2 and nitrogen oxides by this method removes sulfate and nitrate precursors from the stack release, and can therefore reduce the rate of secondary pollutant formation. Various wet scrubber designs are used, but only the variable throat venturi has been commercially effective at removing fine particles from boiler plant combustion gases. For very small particle diameters, collection efficiency is much less than 40% (MCDCE 1978, p. 93).

The most efficient method for fine-particle control is the fabric filter, which can provide high collection efficiencies for particles of 0.5 μ diameter, and reasonable control of ultrafine materials (≤0.1 μ) (MCDCE 1978, p. 99). Baghouses of woven glass fiber filters are most often used in conjunction with coal-fired boilers, with flue gas being drawn through the bag from inside. The loose cake that forms within the bag provides an additional sieving function until it is removed to a collection hopper by shaking or reverse air flow. Fine-particle collection efficiencies of several glass fiber filter baghouse designs have exceeded 99% for all common boilers (MCDCE 1978, pp. 107-112).

E.4 TRACE ELEMENTS

The amounts of trace elements emitted from coal-fired facilities are highly variable, based on the type of coal used and the engineering of the powerplant. The amounts and relative percentages of the trace elements incorporated in coal depend on the geology of the coal-forming basin (Zubovic 1975). Considering this variability, it is not appropriate to attempt to calculate any national averages for trace elements in coal, and care must be taken when averaging regional coal trace element composition (Magee 1973; Dvorak 1977). The distribution of some potentially hazardous trace elements in coals from four coal regions is shown in Table E.5.

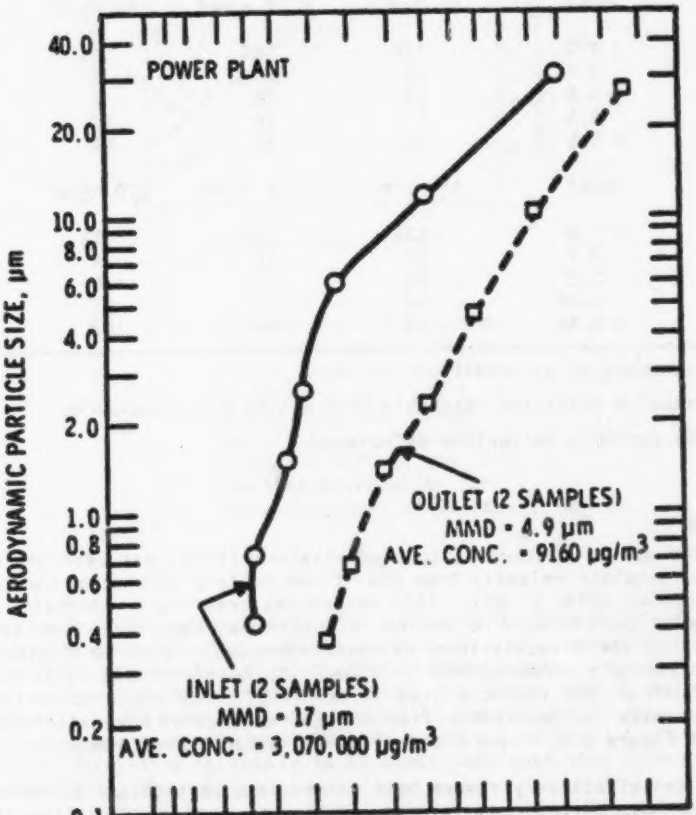

Fig. E.4. Composite Mass Size Distribution of Particulates Collected Before and After an Electrostatic Precipitator at Coal-Fired Powerplant. From Lee et al. (1975). Reprinted with permission from Environmental Science and Technology 9(7):643-647. Copyright 1975, American Chemical Society.

Table E.5. Distribution of Some Potentially Hazardous Trace Elements in Coal (ppm in coal)

	Region			
Element	Powder River Basin	Western Interior	Eastern Interior	Appalachian
Antimony	0.67	3.5	1.3	1.2
Arsenic	3	16	14	18
Beryllium	0.7	2	1.8	2.0
Cadmium	2.1	20	2.3	0.2
Mercury	0.1	0.13	0.19	0.16
Lead	7.2		34	12
Selenium	0.73	5.7	2.5	5.1
Zinc	33		250	13

From Zubovic (1975), Table 3, p. 12A.

During combustion, trace elements tend to concentrate in to varying degrees three fractions that ultimately affect their emission: Group I--those that are not volatilized, but melt and become bottom ash and slag or are emitted from the stack as fly ash; Group II--those that are volatilized but condense out on the fly ash particles as the flue gas cools; and Group III--those that are volatilized and remain almost completely in the gas phase (Klein et al. 1975; Parker and Ray 1977). These elements are listed by group in Table E.6.

Trace elements in outdoor air are associated primarily with particulate matter (Friedlander 1973). Natusch (1978) found that arsenic, antimony, cadmium, lead, selenium, and thorium were most concentrated on the smallest respirable particules due, in theory, to preferential adsorption. These particles are the most difficult to control using pollutant removal equipment. For reasons of toxicity, bioaccumulation, and widespread exposure, trace elements of potential health concern from increased coal utilization include those listed in Table E.7. A panel of toxicologists (Morrow et al. 1977) compared predicted concentrations of certain trace elements with acceptable concentrations (Table E.8) and concluded that there is highly suggestive evidence that beryllium, nickel, cadmium, chromium (Cr IV), arsenic (As III), fluoride, and uranium may present the greatest potential problems among the trace elements listed in Table E.7. Van Hook (1979) adds mercury to this list and the U.S. Office of Technology Assessment (1979) adds selenium. The "Rall Report" (U.S. Department of Health, Education and Welfare 1978) also notes the potential additional health effect of trace elements acting as catalysts for converting sulfur dioxide to acid sulfates. However, trace element emissions are expected to assume a minor role in comparison to other pollutants emitted by coal combustion and in comparison to other sources of these trace elements. The above elements are addressed in detail in Walsh et al. (1981), and although there is potential for concern with some elements, none has been found to constitute a definite regional hazard.

E.5 RADIONUCLIDES

Coal contains small quantities of U-238, U-235, Th-232 and their radioactive daughter products. A survey of the uranium and thorium concentrations in coal samples from all regions of the United States demonstrates that the radionuclide content of coal is quite variable both between and within the various coal supply regions. As coal is burned, some of this natural radioactivity is released into the atmosphere as fly ash; the remainder is in the bottom ash, and its fate is dependent upon ash disposal practices. An estimate of airborne radioactive materials released from a model 1000-MWe coal-fired powerplant was made recently by McBride et al. (1978).

Exposure to radioactivity in fly ash is mainly by inhalation of small particles, ingestion of contaminated terrestrial foods, and direct radiation from deposition on ground surfaces. The ingestion pathway represents the largest potential exposure mode, but this pathway is highly dependent upon the quantity of agricultural crops growing in the vicinity of a coal-fired plant. Radiation doses and exposure pathways from the study by McBride et al. (1978) are given in Table E.9. The ingestion doses estimated in this study are based on an assumption that all food is grown and consumed in the study area (area within 80 km, or 50 mi, of the plant).

Table E.6. Distribution of Trace Elements in Coal Combustion Residues

Group I - Equally distributed in bottom ash and fly ash			
Barium	(Ba)	Manganese	(Mn)
Chromium	(Cr)	Rubidium	(Rb)
Cerium	(Ce)	Scandium	(Sc)
Cobalt	(Co)	Samarium	(Sm)
Europium	(Eu)	Strontium	(Sr)
Hafnium	(Hf)	Tantalum	(Ta)
Lanthanum	(La)	Thorium	(Th)
Group II - Preferentially concentrated in fly ash			
Arsenic	(As)	Lead	(Pb)
Beryllium	(Be)	Antimony	(Sb)
Cadmium	(Cd)	Selenium	(Se)
Copper	(Cu)	Uranium	(U)
Gallium	(Ga)	Vanadium	(V)
Molybdenum	(Mo)	Zinc	(Zn)
Nickel	(Ni)		
Group III - Discharged as vapors			
Chlorine	(Cl)	Mercury	(Hg)
Fluorine	(F)		

Adapted by U.S. Office of Technology Assessment (1979) from Parker and Ray (1977).

Table E.7. Trace Elements of Potential Health Concern from Increased Coal Use

- Antimony
- Arsenic (AsIII)
- Beryllium
- Bromine
- Cadmium
- Chromium (CrIV)
- Copper
- Fluoride
- Gallium
- Iodine
- Iridium
- Lead
- Manganese
- Mercury
- Molybdeum
- Nickel
- Radon
- Selenium
- Titanium
- Thallium
- Thorium
- Uranium
- Zinc

From Comar and Nelson (1975), Heit (1977), Morrow et al. (1977), Santhanan et al. (1979), U.S. Office of Technology Assessment (1979), and Van Hook (1979).

Table E.8. Predicted and Acceptable Air Concentrations of Airborne Trace Elements in the Vicinity of a 1400-MWe Coal-Fired Powerplant

Element	Predicted Air Concentrations ($\mu g/m^3$)	Acceptable Air Concentrations ($\mu g/m^3$)
Arsenic (As(V) or total)	1.2×10^{-4}	0.1
Arsenic (As(III))		1×10^{-5}
Beryllium	2.9×10^{-4}	5×10^{-3}
Cadmium	1.2×10^{-4}	0.05
Chromium	7.2×10^{-6}	0.05
Chromium (Cr(VI insol))		1×10^{-6}
Fluoride	2×10^{-4}	0.01
Mercury	1.2×10^{-3}	0.1
Mercury-organic		0.01
Molybdenum	2.4×10^{-4}	0.1
Nickel	4.8×10^{-4}	0.01
Nickel carbonyl		1×10^{-6}
Lead	2.4×10^{-4}	1.0
Antimony	2.4×10^{-5}	0.1
Selenium	2.4×10^{-5}	0.1
Thallium	3.0×10^{-6}	0.01
Uranium	3.0×10^{-3}	0.01
Vanadium	2.4×10^{-4}	0.05

From Morrow et al. (1977).

Table E.9. Radiation Doses and Pathways of Exposure from a Model 1000 MWe Coal-Fired Powerplant

Organ	Individual[a] (mrem/yr)	Population[b] (man-rem)	Percent Contribution to Dose[c]		
			Ingestion	Inhalation	Surface
Whole body	1.9	21	93.6	5.5	0.9
Bone	18.2	225	82.9	17.0	0.1
Lungs	1.9	29	62.4	37.2	0.4
Kidneys	3.4	50	85.4	14.4	0.2
Liver	2.4	29	93.1	6.5	0.4

From McBride et al. (1978).

[a] Maximum dose to individual at 0.5 km distance.

[b] Dose to 3.5 million persons living within 80 km of the release point (100-m stack).

[c] Dose to population.

Therefore, coal-fired plants in urban areas with little agriculture could be expected to have less exposure via ingestion of contaminated food. Inhalation would be the major exposure pathway. However, more people may live in the urban setting, so that population dose (man-rem) could be as high as when ingestion pathways are significant. In any case, population doses are very similar to those for persons exposed to radiation from routine releases from nuclear powerplants. Moreover, the combustion of coal containing more than 1 ppm uranium and 2 ppm thorium or fly ash treatment systems that release more than 1% of the ash could be expected to lead to higher radiation doses than those cited here.

Additional exposure would be expected from the bottom ash, depending upon the fate of this material, which may be treated as waste or used for construction purposes.

The radiation doses cited in Table E.9 are far below those incurred from naturally occurring background radiation and thus are not expected to result in any increased risk to public health.

E.6 POLYCYCLIC ORGANIC MATTER

Polycyclic organic matter (POM) may be formed during the combustion of fossil fuels or other materials containing carbon and hydrogen. The two classes of POM compounds found most often in ambient air are polycyclic aromatic hydrocarbons (PAHs) and their neutral nitrogen analogues (Syracuse Research Corporation 1980, p. 1-1). These two chemical groups have been shown to contain a number of carcinogenic agents (National Academy of Sciences 1972). As a consequence, the PAHs, and more specifically the potent carcinogen benzo[a]pyrene (BaP), have been the most extensively studied POM compounds.

At the present time, BaP concentrations in the atmosphere provide the most widely available indicator of PAHs. While some investigators have found good correlations between BaP and other PAHs (Sawicki 1967), this relationship is likely to depend on and vary with the type of POM emission sources (National Academy of Sciences 1972, p. 32; Syracuse Research Corporation 1980, pp. 1-4).

There are some data on the magnitude of POM exposures from coal-fired powerplants. Diehl et al. (1967) have determined the emission levels of three polynuclear hydrocarbons from coal-fired units of varying type and size (Table E.10). The National Academy of Sciences (1972, pp. 22-35) has estimated that on a nationwide basis BaP emissions from coal-fired powerplants are about 1 ton per year compared to a total of 1320 tons per year from all major source categories. The National Academy of Sciences ratio of 1:1320 implies that total BaP emissions from coal-fired powerplants are neglible compared with emissions from other sources. However, older measurements using instack collection methods of fly ash sampling may reflect on a small fraction of the total organic material emitted (Natusch 1978; Van Hook and Shults 1976, p. 69) because most organic emissions are in the vapor phase within stacks and do not condense onto the surfaces of fly ash particles until the stack plume has cooled to 100-200°F, some distance from the stack mouth.

The association between POM and particles in the atmosphere is important in the consideration of health effects. Many studies indicate that BaP primarily is associated with particulate matter, the great majority of which is in the respirable size range, about 0.1 to 2 μm in diameter (Syracuse Research Corporation 1980, pp. 3-27 to 3-34). (POM preferentially condenses onto small particles because of their larger surface-to-volume ratio.) Thus, almost all the POM emitted from coal-fired powerplants is capable of deposition in the respiratory tract, given the joint presence of small particles upon which it may be absorbed.

Control technologies that efficently control small particles also can aid in the control of POM. Scrubber systems using low-energy scrubbers to condense the gaseous POM and high-energy scrubbers to remove the fine particles formed should be more effective in controlling POM emissions (Siebert et al. 1978, p. 52) than electrostatic precipitators and fabric filters.

An additional important factor in determining POM concentrations is the efficiency (or completeness) of combustion. The concentrations of BaP associated with coal combustion can vary by a factor of 10,000, depending on the efficiency of the system in question; the BaP emission factor for efficient, modern utility plants is 20-400 μg/10^6 Btu, while the corresponding figure for hand-stoked residential coal furnaces is 1,700,000-3,300,000 μg/10^6 Btu (National Academy of Sciences 1972, p. 23). Some sources (U.S. Department of Health, Education, and Welfare 1978; Spengler et al. 1979) have indicated concern over the possibility of increased POM emissions from smaller, less efficient, coal-fired industrial facilities located in or near high-density population areas. "While modern utility plants are designed to efficiently utilize the fuel value of the coal (and thereby reduce POM emissions), the conversion of older industrial facilities, from oil and gas to coal would expose a large population to elevated concentrations of POM. This is particularly important for those older facilities with low stacks located in urban areas" (Spengler et al. 1979, p. 3-62). Table E.10 illustrates that the smaller, less efficient installations emit more polynuclear hydrocarbons per million Btu input and per 1000 m^3 of the flue gas. However, in terms of emission rate (per unit time), the larger units actually emit

Table E.10. Polynuclear Hydrocarbon Concentrations in the Flue Gases of Coal-Fired Power Units

Type of Burner	Capacity (lb steam/hr)	Load factor sampled	Benzo(a)pyrene			Benzo(e)pyrene			Benz(a)anthracene		
			μg/1000 m^3	μg/10^6 Btu	mg/hr	μg/100 m^3	μg/10^6 Btu	mg/hr	μg/1000 m^3	μg/10^6 Btu	mg/hr
Chain grate	33,000	0.61	-	-	-	250	119	3.5	-	-	-
Chain grate	35,000	0.45	9	4	0.1	91	42	1.0	44	20	0.4
Chain grate	40,000	0.47	110	75	2.8	440	300	11	-	-	-
Chain grate	52,000	0.41	850	500	20	530	310	12	1,400	820	32
Chain grate	55,000	0.81[a]	-	-	-	-	-	-	-	-	-
Underfeed	160,000	0.74	240	120	13	140	72	7.7	380	200	21
Underfeed	25,000	0.40[a]	53	31	1.1	590	350	12	-	-	-
Spreader	24,000	0.75	120	68	1.3	820	470	9.1	-	-	-
Pulsating grate	2,470	1.00	650	330	1.3	1,300	670	2.7	1,300	670	2.7
Pulverized coal	40,000	0.80	420	230	9.1	860	470	19	400	220	0.7
Pulverized coal	240,000	0.88	180	120	45	1,300	880	330	-	-	-
Pulverized coal	600,000	1.10	-	-	-	160	64	.06	-	-	-
Pulverized coal	830,000	1.05	66	21	31	110	34	50	-	-	-
Pulverized coal	1,060,000	1.00	18	6	10	380	130	220	-	-	-
Pulverized coal	1,250,000	1.02	80	32	59	68	27	50	-	-	-
Pulverized coal	2,030,000	0.78	59	20	54	130	44	120	-	-	-
Pulverized coal	2,100,000	0.85	56	17	28	120	37	62	-	-	-
Cyclone	2,200,000	0.99	40	16	49	140	55	170	-	-	-

From Diehl et al. (1967).

[a] Fluctuating load.

more PAHs due to their much higher fuel input and larger volume of flue gas produced per unit time. It is difficult to gauge the importance of these issues for the 42 Northeast Region powerplants with the information now available. Final combustion efficiences will depend largely on equipment modifications and replacements that will accompany the conversion process.

The atmospheric stability of POM and its ability to be transported from the emission source to other locations is pertinent to the assessment of possible population exposures. Evidence suggests that many POM compounds oxidize or photodegrade at a significant rate under atmospheric conditions. The atmospheric lifetime of a POM particle is related to particle size, with small (<1 μm in diameter) particles having a longer atmospheric residence time. However, the reaction rates of compounds on smaller particles is likely to be faster because of the greater surface area exposed to oxidants and light (Syracuse Research Corporation 1980, pp. 3-35 to 3-47). In contrast, there is some evidence that many POM compounds are relatively stable in the atmosphere in the form in which they are naturally present and are able to travel distances of several hundred miles (Lunde and Bjorseth 1977).

A number of POM compounds have been detected in ambient air but the most extensive monitoring data exists for BaP. Urban BaP concentrations in the U.S. have been declining steadily with average concentrations of 6 ng/m^3 in 1958 (Sawicki 1967), 3.2 ng/m^3 in 1966, and 0.5 ng/m^3 in 1975 (Syracuse Research Corporation 1980, p.5-20). The decline is attributed primarily to decreases in residential coal combustion and restrictions on open burning.

Exposure to relatively high levels of POM-containing substances has resulted in various noncancerous skin and eye responses in a number of clinical and occupational settings. Skin effects have been produced in the clinical setting through the application of coal tar and coal solutions to the skin of human subjects, often in conjunction with exposure to ultraviolet light. Responses to this type of exposure include (tar phototoxicity) or irritation of the skin (Tanenbaum et al. 1975; Kaidbey and Kligman 1977), decreased mitotic cell division (Fisher and Maiback 1973), and induction of aryl hydrocarbon hydroxylas (AHH), a carcinogen-metabolizing enzyme that may induce cancer, on the skin (Bickers and Kappas 1978).

Non-cancerous skin effects also have been observed in occupational settings. These include nonallergic and allergic dermatitis, phototoxicity and photoallergic reactions, folliculitis, acne, and pigment disturbances. Effects have occurred following exposure to coal tar and coal tar products, pitch, creosote, asphalt, and petroleum products (National Academy of Sciences 1972). Additional sources have reported the occurrence of acute eye effects following exposure to coal tar pitch, including inflamation, conjunctivitis, and reduction in visual acuity (Emmett et al. 1977).

Skin carcinomas historically have been observed in occupations having exposure to high-temperature coal tar products (SRI International 1977, pp. 30-73; National Academy of Sciences 1972; Henry 1947). Studies of occupational groups exposed to POM, many among coke plant workers (Lloyd 1971) and gas production workers (Doll et al. 1965) and others from the roofing and asphalt industries (Hammond et al. 1976), have shown that long-term exposure to the products of coal distillation is associated with an elevated rate of lung cancer and, in some cases, cancer of other parts of the body (see Walsh et al. 1981).

Community air pollution studies typically involve much lower (two to four orders of magnitude) levels of ambient exposure than the levels observed in occupational settings. In these studies an investigation is made of the possible associations between community mortality and morbidity rates and some direct or indirect measure of air pollution (see Walsh et al. 1981).

In a considerable number of studies, urban and rural populations have been compared in an attempt to attribute any differences in rate to greater air pollution in urban areas. These studies tend to show, in males, a fairly consistent excess (about two-fold) in urban lung cancer rates over those found in the corresponding rural areas (Manos and Fisher 1959; Levin et al. 1960; Haenzel et al. 1962; Stocks and Campbell 1955). However, at the present time there is no general consensus that these differences are due to air pollution. In community study efforts, as well, also have correlated cancer mortality rates with indices of air pollution, but the results of these studies have been inconsistent. Menck et al. (1974) found a correlation concentration of ambient BaP and the lung cancer mortality excess of 40% in south central Los Angeles County. Henderson et al. (1975) also found correlations between lung cancer cases and industrial emissions of PAHs. On the other hand, Higgins (1977) found no association between BaP levels and lung cancer mortality rates in 50 U.S. Standard Metropolitan Statistical Areas.

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APPENDIX B

AIR QUALITY

CONTENTS

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APPENDIX B

AIR QUALITY

B.1 INTRODUCTION

This document presents background data pertinent to the analyses of air quality baseline conditions (Section 3.3) and air quality construction and operation impacts discussed in the EIS with regard to the various alternative actions.

This document provides background data pertinent to discussions of air quality presented in the Environmental Impact Statement (EIS), for the Mt. Tom generating station, Holyoke, Massachusetts.

Section B.2 of this document provides information on expected fugutive dust emissions.

Section B.3 is a review of the types of emissions which may be expected under the different alternatives discussed in the EIS, including their effects on the environment. This section also quantifies emissions of various pollutants that could be expected under each alternative.

Section B.4 is a review of the modeling studies required by EPA Region I.

B.2 FUGITIVE DUST EMISSION RATES

Fugitive dust emissions are not easily quantifiable - a wide variation in estimates of emission factors for any particular source type can be found in the literature. Estimates of the emission factor for the same source type that differ by several orders of magnitude can frequently be found. For example, the emissions from any particular source are sensitively dependent on the physical and chemical nature of the material being handled, the wind speed and gustiness at the time of emission, the geometry of the source, and the climate of the region in which the source is located. Furthermore, both theoretical calculations and empirical measurement of fugitive dust emission factors are subject to large uncertainties. Therefore, one should not put a great deal of confidence in quantitative treatments of air quality effects of fugitive dust emissions. The discussion in this section consequently is limited to qualitative or semi-quantitative results.

Major fugitive dust sources at the Mt. Tom generating station under the low-sulfur coal conversion will be a coal car shaker and hoppers for coal unloading, from rail deliveries, loading and unloading facilities at the coal storage pile, wind erosion from the storage pile, coal conveyors, and the coal crusher house.

The anticipated unloading equipment will be capable of unloading 7,000 tons of coal in 14 to 16 hours, for a maximum unloading rate of 500 tons per hour. An uncontrolled emission factor of 0.017 lb/ton for coal car dumping was taken from USEPA (1978a). If it is assumed that the enclosure of the dumper provides 50 percent control of the fugitive emissions, then a maximum emission rate for the coal car dumper of 0.5 g/s results. This maximum rate would obtain only during actual operation of the coal car dumper. Over a longer term average, the coal handling rate should equal the average coal consumption rate at Mt. Tom, which would be 44 tons per hour, assuming an annual average capacity factor of 80 percent. The long-term average emission rate from the dumper would thus be 0.05 g/s.

For coal transfer and conveying sources, an emission factor of 0.2 lb/ton (the geometric mean of a range of values between 0.04 lb/ton and 0.96 lb/ton) was taken from USEPA (1977). The coal handling rate was assumed to be the maximum Mt. Tom consumption rate of 55 tons/hour, and it was assumed that the partial enclosure of the conveyor and the transfer points would provide 50 percent control of the emissions. An emission rate of 0.7 g/s then results from this source.

For the coal crusher, an uncontrolled emission rate of 0.1 lb/ton was taken from USEPA (1980) (this rate applies to primary stone crushing). The coal handling rate was assumed to be 55 tons/hour, and the crusher house enclosure was assumed to provide 85 percent control of the emissions. The resulting emission rate from this source is then 0.1 g/s.

For wind erosion from the coal storage pile, the emission rate was calculated according to a method (depending on the average wind speed, the bulk density of coal, the surface area of the coal pile, and the precipitation-evaporation index for Holyoke) presented in USEPA (1978b). The resulting estimated emission rate is 0.01 g/s.

The estimated maximum total fugitive emission rate for the low-sulfur coal conversion is thus approximately 1.3 g/s. (By comparison, the maximum particulate matter emissions from the stack would be approximately 83 g/s during the DCO period, and approximately 14 g/s following installation of a new ESP.) A large fraction of the fugitive dust particles (perhaps 70 percent) would be large enough to quickly settle out of the windborne plume. Such particles would generally not be carried outside the plant boundaries, except, perhaps, under extremely windy conditions.

Additional fugitive dust control methods that might be included in the low-sulfur coal conversion scenario are listed below:

1) Wet suppression spray at the coal car dumper and at other transfer points.

2) Bag filter venting of the coal car dumping and crusher house structures.

3) Periodic wet spraying of the coal storage pile.

4) Use of a telescoping boom for loading coal to the storage pile.

The total effect of these additional control measures could be an approximate 50 percent reduction in the fugitive dust emissions.

B.3 STACK EMISSIONS CALCULATIONS

B.3.1 Types of Emissions

B.3.1.1 Sulfur Dioxide

SO_2 is an irritant to human respiratory system tissue. When inhaled, SO_2 can increase respiration rate and decrease pulmonary system tidal volume, the volume of air exchanged with the atmosphere with each breath. When in conjunction with suspended fine particles inhaled into the moist lung environment, oxidation of SO_2 to sulfuric acid can occur with subsequent direct tissue damage by acid exposure. Prolonged exposure can lead to chronic respiratory disease (Williamson, 1973). SO_2 causes immediate irritation at concentrations above 65,000 $\mu g/m^3$ and can be smelled at 7,800 $\mu g/m^3$.

SO_2 causes plant and material damage above threshold values that vary among different receptors. It affects plant leaves and can reduce crop yields or germination rates for sensitive species under extreme conditions. Prolonged exposure to sulfurous smogs damages building material, corrodes metal, and discolors paint.

Sulfur dioxide in the ambient air oxidizes and hydrolyzes to form sulfuric acid and often is partially neutralized to form sulfates. However, there are no simple relationships between the amount of emitted SO_2 and concentrations of atmospheric sulfate. The Sulfate Regional Experiment (SURE), an independent Energy Research and Development Administration (now in part DOE) program, and experiments in Canada and Europe are designed to investigate the relationships between SO_2 emissions and sulfate concentrations. A preliminary study associated with SURE found that local ambient sulfate levels correlate poorly with local and subregional SO_2 levels; that the regional distribution of sulfates cannot be explained by any simple conversion theories; that the sulfate maxima in summer and minima in winter correlate negatively with SO_2 maxima and minima; and that sulfate concentrations seem to correlate with both temperature and humidity (Perhac, 1978).

Eventually, some fraction of emitted SO_2 may travel downwind for periods of time long enough to be converted to sulfates or sulfuric acid, and subsequently to be brought to ground by acid rain or dry deposition processes. These are regional scale processes for which the contribution due to any particular source is largely obscured. The possible effects of this type for region-wide SO_2 increases due to coal conversions are treated by the Northeast Regional EIS (DOE, 1981).

B.3.1.2 Particulate Matter

Particles suspended in the atmosphere can cause serious respiratory problems. Although sulfur particles (sulfates) produced by the combustion of fossil fuel are especially dangerous, any fine particles inhaled and deposited in the lungs can irritate enough to cause diseases such as bronchitis, emphysema, and lung cancer (Williamson, 1973).

Fine suspended particles, ranging in size from 0.2 micron to 2.0 microns, can decrease visibility and reduce solar radiation at the surface. Visibility can be reduced to 5 miles for a PM concentration of 150 $\mu g/m^3$ and a relative humidity less than 70 percent. Direct solar radiation is reduced by one third during summer and two thirds during winter in middle and high latitudes for PM concentrations between 100 and 150 $\mu g/m^3$.

Public opinion survey data in several cities indicate a positive relationship between general public awareness of air pollution and the levels of PM concentration. Whether or not they consider air pollution an annoyance relates to the frequency of acute pollution incidents and their socioeconomic status (HEW, 1969).

B.3.1.3 Nitrogen Oxides

Nitrogen oxides (NO_x) are formed mainly from high temperature combustion followed by rapid cooling. Nitrogen oxides resulting from oil and coal combustion appear primarily as nitric oxide (NO), which is subsequently oxidized in the atmosphere to more toxic nitrogen dioxide (NO_2). Nitrogen oxides also affect the formation of photochemical oxidants. Both NO and NO_2 participate in complex atmospheric reactions with ozone (O_3) and organic radicals derived from hydrocarbon emissions. The principal ozone formation mechanism consists of NO_2 reacting with oxygen in the presence of sunlight, while the principal ozone destruction reaction is with NO to produce NO_2.

Chemical reactions of nitrogen oxides with water and other atmospheric contaminants lead to the formation of compounds that contribute to acid rain and dry acid deposition at distant downwind locations.

B.3.1.4 Carbon Monoxide

Carbon monoxide (CO) in the urban environment arises primarily from incomplete combustion of carbonaceous fuels. The largest source of CO is the combustion of gasoline by motor vehicles. The highest ambient concentrations of CO are found near heavily travelled urban expressways and streets. The Mt. Tom generating station's contribution of CO is minimal compared with that of automobiles; 250 vehicle-miles per-hour (equivalent to 50 vehicles travelling over a 5-mile stretch of road during one hour) produce more CO than a small generating station such as Mt. Tom.

CO's major effect is on public health. CO is a toxic chemical compound that damages cardiovascular-respiratory functions. It can also impair time interval discrimination, visual acuity, and other psychomotor functions when humans are exposed briefly to high levels of this gas.

CO emissions from generating stations are reduced as combustion efficiency increases. Careful control of excess air rates, the use of high combustion temperature, and provision for intimate fuel-air contact will minimize CO emissions.

B.3.1.5 Hydrocarbons

Hydrocarbons (HC) are organic compounds that consist solely of hydrogen and carbon and arise from incomplete combustion of carbonaceous fuels, industrial process evaporative losses, and other fuel-use activities.

The automobile is the major source of anthropogenic hydrocarbons. By comparison, the Mt. Tom generating station produces only a small amount of HC. For example, 600 vehicle-miles-per-hour (equivalent to emissions produced by 150 vehicles travelling over a 4-mile stretch of road during one hour) would produce more HC than a generating station the size of Mt. Tom. There are no monitoring stations measuring ambient HC levels in the study area.

Hydrocarbons are not a direct health hazard, but they combine with nitrogen oxides in a complex series of chemical reactions to form hazardous photochemical oxidants (ozone) as discussed in the next section.

The alternative fuel options would entail estimated HC emissions considerably larger than either the oil burning or low-sulfur coal conversion scenarios. Assuming an annual capacity factor of 80 percent, the use of RDF to replace 20 percent of the station heat energy needs would increase HC emissions to 189 tons/year, and the use of wood chips as the primary fuel would increase HC emissions to 640 tons/year.

Either of these alternatives would thus involve increased HC emissions of more than 100 tons per year. Mandatory fuel conversions under ESECA and fuel conversions designed to use RDF are exempt from the nonattainment offset provisions of the CAA, so that the large increases in HC emissions attendant on these conversions would not legally require emissions offsets. Nonetheless, these HC increases in an ozone nonattainment area would be an adverse air quality effect.

A potential air quality effect from the use of RDF could be the release of toxic gases into the atmosphere. Such extremely toxic gases as dioxins have been identified in small concentrations in RDF flue gas streams (Ogg and Menczel, 1981). The extent of such emissions and the potential health hazards therefrom are currently only very poorly known.

B.3.1.6 Ozone/Oxidants

Oxidants are the product of a set of complex atmospheric chemical reactions that are difficult to simulate, so the impact of the conversion cannot be quantitatively evaluated. Therefore, we present here a qualitative discussion that may apply to any of the possible fuel scenarios. We can presume that ozone concentrations will increase somewhat because in most of the scenarios HC is predicted to increase. However, the HC and NO_2 produced by the Mt. Tom generating station will probably not contribute to levels in the immediate area, but might in more distant regions. The effect of all regional coal conversions on O_3 is assessed in the Draft Northeast Regional EIS (DOE, 1981).

The observed effects of photochemical oxidants include eye and respiratory irritation. High oxidant levels lead to dulled senses, impaired vision, and increased driver irritability. Photochemical oxidants are also known to damage textiles, dyes, and paint.

Williamson (1973) states that respiratory system irritation during smoggy days is most noticeable to those who participate in vigorous exercise. There is no evidence that the temporary distress of a healthy person exposed to an oxidant level of about 600 $\mu g/m^3$ produces long-term effects. Similarly, there is no firm evidence that the exposure aggravation of chronic lung disease symptoms leads to an ultimate deterioration of the patient's condition.

There are no direct emissions of ozone, but ozone reduction can be achieved through limitations on NO_2 and hydrocarbon emissions. State plans for controlling ozone in nonattainment areas were to have been developed by the states by January 1, 1979 and approved by EPA by July 1, 1979. Any controls of either NO_2 or HC for the purpose of reducing ozone impacts will be contained in these plans. Since the states are expected to attain ambient ozone standards by December 1982 (1987 at the latest), the generating station might be subject to future mitigation requirements not yet promulgated.

B.3.1.7 Trace Elements

A sizeable fraction of the many trace elements in fuel will appear in the ash residue of the combustion process and will be subject to the removal mechanisms applicable to the total ash formed, that is, deposition as bottom ash and collection by particulate matter control equipment. Some elements, such as mercury, will vaporize in the combustion zone and can escape in a gaseous form; others, such as cadmium, lead, and zinc, apparently vaporize and then preferentially adhere to very fine particles that are not collected with the same degree of efficiency as the bulk of the ash material (Klein and others, 1975). As for ozone, no quantitative calculation of emissions for each scenario is possible. Therefore, only a general qualitative discussion is provided.

Ground-level concentrations of trace elements resulting from fuel combustion are typically very low, well below the industrial hygiene standards that have been established to control occupational exposure to trace elements. Although occupational standards are established on a different basis and directed toward a somewhat different population than are ambient standards, achieving compliance with occupational standards by a wide margin would indicate that adverse health effects attributable to trace element emissions will be avoided.

B.3.2 Emissions If NOE Not Issued (No Action Alterrative)

The pollutant emissions from the Mt. Tom generating station stack for the case of return to combustion of fuel oil as the primary fuel are described in this section. It is assumed that the station would operate continuously on fuel oil that would satisfy the SIP sulfur-in-fuel limitation of 1.21 lb sulfur per million Btu heat input. This limitation corresponds to a No. 6 fuel oil having a sulfur content of 2.2 percent by weight.

The heating rate for oil burning at Mt. Tom is 9.532 x 10^6 Btu/ MW-hr (Powell, 1981). This implies a heat consumption rate of 1382 x 10^6 Btu/hr when the plant is operating at the design rate of 145 MW. In 1979, the average heat content of the fuel oil consumed was 148,654 Btu/gallon. The full-capacity oil consumption rate with this fuel is 9.297 x 10^3 gal/hr.

The emission rates calculated below correspond to full-capacity operation of the plant and are appropriate for maximum short-term rates. For annual average emissions, the emission rates given should be multiplied by an annual capacity factor of about 80 percent, which reflects the fraction of time during a year when the unit could be expected to be out of operation for maintenance and repair.

B.3.2.1 Sulfur Dioxide

The SO_2 emission rate is calculated from the SIP sulfur-in-fuel limit and an assumption that 5 percent of the fuel sulfur content is retained in the ash. Then the SO_2 emission rate (QSO_2) is given by:

$$QSO_2 = \left(2 \frac{\text{lb } SO_2}{\text{lb S}}\right) \left(1.21 \frac{\text{lb S}}{10^6 \text{ Btu}}\right) \left(1382 \frac{10^6 \text{ Btu}}{\text{hr}}\right) (0.95)$$

$$= 3177 \text{ lb } SO_2/\text{hr}$$

$$QSO_2 = 400 \text{ g/s } SO_2$$

Annual average capacity is expected to be 80 percent. Therefore:

$$QSO_2 = 400 \text{ g/s } SO_2 \ (.80)$$

$$QSO_2 = 320 \text{ g/s } SO_2 \text{ on an annual basis.}$$

B.3.2.2 Particulate Matter

An uncontrolled PM emission rate is calculated from the emission factor provided by the EPA pollutant emissions handbook AP-42 (USEPA, 1980). The appropriate AP-42 emission factor for fuel oil combustion is (10 S + 3) lb PM per 10^3 gallons of oil burned, where S is the fuel sulfur content by weight, in the present case, 2.2. Then:

$$QPM = [10\ (2.2) + 3] \frac{\text{lb PM}}{10^3 \text{ gal}} \left(9.297 \frac{10^3 \text{ gal}}{\text{hr}}\right)$$

$$= 232 \text{ lb PM/hr}$$

$$QPM = 29.3 \text{ g/s PM}$$

Note that the uncontrolled emission rate of 232 lb/hr PM is larger than would be allowed by the SIP limit of 0.12 lb PM/10^6 Btu, which permits:

$$QPM_{SIP} = (0.12\ \frac{\text{lb PM}}{10^6\ \text{Btu}})\ (1{,}382\ \frac{10^6\ \text{Btu}}{\text{hr}})$$

$$QPM_{SIP} = 166\ \text{lb/hr PM}$$
$$= 20.9\ \text{g/s PM}$$

Therefore, the use of the ESP is necessary when 2.2 percent sulfur fuel oil is fired.

The regulatory agency review (by EPA Region I) of the effects of the Delayed Compliance Order and SIP Revision for the Mt. Tom generating station fuel conversion must consider only changes in allowed emission rates, not the actual emission rates. For the purposes of the regulatory review, then, the pertinent QPM value is 20.9 g/s. The actual PM emission rate from the Mt. Tom stack under normal full-load operations, which includes use of the ESP, has been determined by stack testing to be 8.0 g/s. This value is about 38 percent of the allowed maximum.

B.3.2.3 Nitrogen Oxides

Nitrogen oxide emissions are conservatively estimated to be entirely nitrogen dioxide, NO_2. The AP-42 uncontrolled NO_2 emission factor of 105 lb $NO_2/10^3$ gal for No. 6 fuel oil is assumed. Then the emission rate for NO_2 is given by:

$$QNO_2 = (105\ \frac{\text{lb } NO_2}{10^3\ \text{gal}})\ (9.297\ \frac{10^3\ \text{gal}}{\text{hr}}\ )$$

$$= 976\ \text{lb/hr } NO_2$$

$$QNO_2 = 123\ \text{g/s } NO_2$$

The final Draft Environmental Impact Report prepared by the utility (NUSCO, 1981) presents an NO_x emission rate measured by stack testing. The measured emission rate is considerably smaller than the estimate calculated above, and corresponds to a value:

$$QNO_2 = 66.5\ \text{g/s } No_2$$

B.3.2.4 Carbon Monoxide

The appropriate emission factor for CO is 5 lb/10^3 gal. Then:

$$QCO = (5\ \frac{\text{lb CO}}{10^3\ \text{gal}})\ (9.297\ \frac{10^3\ \text{gal}}{\text{hr}})$$

$$= 46.5\ \text{lb/hr CO}$$

$$QCO = 5.9\ \text{g/s CO}$$

B.3.2.5 Hydrocarbons

The appropriate emission factor for unburned hydrocarbons (HC), taken from AP-42, is 1 lb HC/10^3 gal. Then the HC emission rate is:

$$QHC = (1\ \frac{\text{lb HC}}{10^3\ \text{gal}})\ (9.297\ \frac{10^3\ \text{gal}}{\text{hr}})$$

$$= 9.3\ \text{lb/hr HC}$$

$$QHC = 1.2\ \text{g/s HC}$$

B.3.3 Emissions Under the Low-sulfur Coal Conversion Scenario

Under the low-sulfur coal conversion scenario the Mt. Tom generating station converted to a coal fuel with a heat content of 12,500 Btu/lb. The full-capacity heat rate for the station while burning coal is 9,450 Btu/kw-hr (Dames & Moore, 1980). The associated heat consumption rate is 1,370 x 10^6 Btu/hr when the station is operating at the design power rating of 145 MW. The coal consumption rate for this case is then 54.8 ton/hr.

The emission rates given correspond to maximum short-term average values. For annual averages, multiply the given figures by 0.80 to reflect an annual 80 percent capacity factor.

B.3.3.1 Sulfur Dioxide

Under the low-sulfur, SO_2 emission rates would be determined by the following sulfur-in-fuel limitations:

1.21 lbs sulfur/10^6 Btu heat input, for any 30-day period

1.60 lbs sulfur/10^6 Btu heat input, maximum for any 24-hour period

It is assumed that 5 percent of the fuel sulfur will be retained in the ash. Then the SO_2 emission rates are given by:

$$QSO_2\ (24\text{-hr}) = (2\ \frac{\text{lb } SO_2}{\text{lb S}})\ (1.60\ \frac{\text{lb S}}{10^6 \text{ Btu}})(1{,}370\ \frac{10^6 \text{ Btu}}{\text{hr}})(0.95)$$

$$= 4{,}165 \text{ lb/hr } SO_2$$

$$QSO_2\ (24\text{-hr}) = 525 \text{ g/s } SO_2$$

$$QSO_2\ (30\text{-day}) = (2\ \frac{\text{lb } SO_2}{\text{lb S}})\ (1.21\ \frac{\text{lb S}}{10^6 \text{ Btu}})(1{,}370\ \frac{10^6 \text{ Btu}}{\text{hr}})(0.95)$$

$$= 3{,}150 \text{ lb/hr } SO_2$$

$$QSO_2\ (30\text{-day}) = 397 \text{ g/s } SO_2$$

B.3.3.2 Particulate Matter

The PM emissions under the low-sulfur coal conversion differ during the period of the Delayed Compliance Order (DCO) and after the updated PM controls are in place at the end of the DCO period. The emission rates are determined by the following emission factors:

0.48 lb PM/10^6 Btu heat production, maximum during the DCO period.

0.08 lb PM/10^6 Btu heat production, permanently following the DCO period.

The emission rates are consequently:

$$QPM\ (DCO) = (0.48\ \frac{\text{lb PM}}{10^6 \text{ Btu}})(1{,}370\ \frac{10^6 \text{ Btu}}{\text{hr}})$$

$$= 658 \text{ lb/hr PM}$$

$$QPM\ (DCO) = 82.9 \text{ g/s PM}$$

$$QPM\ (Perm) = (0.08\ \frac{\text{lb PM}}{10^6 \text{ Btu}})(1{,}370\ \frac{10^6 \text{ Btu}}{\text{hr}})$$

$$= 110 \text{ lb/hr PM}$$

$$QPM\ (Perm) = 13.8 \text{ g/s PM}$$

B.3.3.3 Nitrogen Oxides

The NO_2 emission rate is estimated using the AP-42 emission factor of 18 lb NO_2/ton coal, for bituminous coal consumed in a dry-bottom boiler.

$$QNO_2 = (18 \frac{\text{lb } NO_2}{\text{ton}})(54.8 \frac{\text{ton}}{\text{hr}})$$

$$= 986 \text{ lb/hr } NO_2$$

$$QNO_2 = 124 \text{ g/s } NO_2$$

B.3.3.4 Carbon Monoxide

The CO emission factor of 1 lb CO/ton coal is taken from AP-42.

$$QCO = (1 \frac{\text{lb CO}}{\text{ton}})\ (54.8 \frac{\text{ton}}{\text{hr}})$$

$$= 54.8 \text{ lb/hr CO}$$

$$QCO = 6.9 \text{ g/s CO}$$

B.3.3.5 Hydrocarbons

The AP-42 emission factor of 0.3 lb HC/ton coal is used.

$$QHC = (0.3 \frac{\text{lb HC}}{\text{ton}})(54.8 \frac{\text{ton}}{\text{hr}})$$

$$= 16.4 \text{ lb/hr HC}$$

$$QHC = 2.1 \text{ g/s HC}$$

B.3.4 Conversion Plus SO_2 Scrubbing

This alternative involves the use of higher sulfur coal together with a flue gas desulfurization (FGD or scrubber) system to control the excess SO_2 emissions and thereby meet the same emission limitations as given in the MOU. Therefore, the SO_2 emissions for this alternative do not differ from those calculated in Section B.3.3.1 for the low-sulfur coal conversion.

The use of higher sulfur coal plus an FGD system would entail increased fugitive PM emissions due to receiving, storing, and handling of large quantities of limestone, lime, or other alkaline raw material for the scrubber. Handling and disposal of sludge produced by the scrubber would also result in increased fugitive PM emissions.

B.3.5 Low-sulfur Coal Conversion with 20 Percent RDF

This alternative scenario is assumed to follow the low-sulfur coal conversion, except that 20 percent of the required heat rate is to be provided by refuse-derived fuel (RDF). The RDF is taken to have a heating value of 5,000 Btu/lb, and the total heat rate requirement is assumed to remain at the coal value of 1,370 10^6 Btu/hr. Emission factors for combustion of RDF are taken as the values in AP-42 for large refuse incinerators.

The RDF consumption rate is $(0.20)(1{,}370 \times 10^6 \text{ Btu/hr})/(5{,}000 \text{ Btu/lb})$
= 27.4 ton/hr

B.3.5.1 Sulfur Dioxide

The AP-42 RDF emission factor is 2.5 lb SO_2/ton.

QSO_2 (24-hr) = (0.80)(4,165 lb/hr SO_2) +
(2.5 lb/ton SO_2) (27.4 ton/hr)

= 3,400 lb/hr SO_2

QSO_2 (24-hr) = 428 g/s SO_2

QSO_2 (30-day) = (0.80) (3150 lb/hr SO_2) + (2.5 lb/ton SO_2) (27.4 ton/hr)

= 2,590 lb/hr SO_2

QSO_2 (30-day) = 326 g/s SO_2

B.3.5.2 Particulate Matter

For RDF combustion, the uncontrolled PM emission factor (from AP-42) is 14 lb/ton PM, which corresponds to 1.4 lb PM/10^6 Btu heat input, a value considerably larger than the low-sulfur-allowed coal emissions. If the PM emissions from the RDF were uncontrolled, the resulting emission rate would be:

QPM (DCO, RDF uncontrolled) = (0.8)(658 lb/hr PM)
+ (14 lb/ton PM) (27.4 ton/hr)

= 910 lb/hr PM

QPM (DCO, RDF uncontrolled) = 115 g/s PM

QPM (Perm, RDF uncontrolled) = (0.8) (110 lb/hr PM) + (14 lb/ton PM)
(27.4 ton/hr)

= 472 lb/hr PM

QPM (Perm, RDF uncontrolled) = 59.4 g/s PM

Because these PM emission rates with uncontrolled RDF PM emissions are considerably larger than the coal-only case (see Section B.3.3 and below), it would not appear likely that RDF combustion could escape controls. If the effluent from RDF combustion were routed through the ESP (which would necessarily occur if the RDF were burned in the same boiler as the coal), then the low-sulfur coal conversion PM emission rates would presumably obtain, namely:

QPM (DCO) = 658 lb/hr PM = 82.9 g/s PM

QPM (Perm) = 110 lb/hr PM = 13.8 g/s PM

B.3.5.3 Nitrogen Oxides

The AP-42 emission factor is 3 lb/ton NO_2.

QNO_2 = (0.8)(986 lb/hr NO_2) + (3 lb/ton NO_2) (27.4 ton/hr)

= 871 lb/hr NO_2

QNO_2 = 110 g/s NO_2

B.3.5.4 Carbon Monoxide

The AP-42 emission factor is 35 lb CO/ton.

QCO = (0.8)(54.8 lb/hr CO) + (35 lb CO/ton)(27.4 ton/hr)

= 1,003 lb/hr CO

QCO = 126 g/s CO

B.3.5.5 Hydrocarbons

The AP-42 emission factor for unburned hydrocarbons is 1.5 lb HC/ton.

QHC = (0.8)(16.4 lb HC/hr) + (1.5 lb HC/ton)(27.4 ton/hr)

= 54.2 lb/hr HC

QHC = 6.8 g/s HC

B.3.6 Wood Chips as Primary Fuel

In this alternative fuel option, it is assumed that the entire supply of heat energy at Mt. Tom generating station (assumed needed at the coal heat rate of 1,370 x 10^6 Btu/hr) is to be supplied by combustion of wood chips. It is assumed that the wood would be air dried before combustion in the boiler (moisture content 12 percent to 15 percent), so that the heat content is 7,500 Btu/lb (Tillman, 1978). The wood chip consumption rate would therefore be:

(1,370 x 10^6 Btu/hr)/(7500 Btu/lb) = 91 ton/hr

The emission factors used here are taken from AP-42, for large woodwaste boilers that are "well-designed and operated."

B.3.6.1 Sulfur Dioxide

The emission factor is 1.5 lb SO_2/ton.

QSO_2 = (1.5 lb SO_2/ton)(91 ton/hr)

= 137 lb/hr SO_2

QSO_2 = 17.3 g/s SO_2

B.3.6.2 Particulate Matter

The uncontrolled emission factor of PM for wood combustion is (5 lb PM/ton)/(7,500 Btu/lb) = 0.33 lb PM/10^6 Btu.

This is considerably larger than the present SIP emission limit of 0.12 lb PM/10^6 Btu for fossil-fuel firing at Mt. Tom generating station, but smaller than the low-sulfur DCO temporary emission limit of 0.48 lb PM/10^6 Btu (first 8 months of DCO only). The Massachusetts SIP contains no limitation on PM emissions for wood burning in an electric utility boiler. Nonetheless, we assume that the fossil fuel SIP limit of 0.12 lb PM/10^6 Btu would be enforced for conversion of Mt. Tom to permanent use of wood as a primary fuel. This would require 64 percent control efficiency from either the presently existing Mt. Tom multiclone and ESP or a replacement control system, a level of control that is perhaps not unreasonable to expect for the system under wood burning operation.

Under these assumptions, the PM emission rate is:

QPM = (0.12 lb PM/10^6 Btu)(1,370 10^6 Btu/hr)

= 164 lb/hr PM

QPM = 20.7 g/s PM

B.3.6.3 Nitrogen Dioxide

The AP-42 emission factor for NO_2 is 10 lb NO_2/ton

QNO_2 = (10 lb NO_2/ton) (91 ton/hr)

= 910 lb/hr NO_2

QNO_2 = 115 g/s NO_2

B.3.6.4 Carbon Monoxide

The AP-42 emission factor for CO is 2 lb CO/ton.

QCO = (2 lb CO/ton)(91 ton/hr)

= 182 lb/hr CO

QCO = 23.0 g/s CO

B.3.6.5 Hydrocarbons

The AP-42 emission factor for HC is 2 lb HC/ton.

QHC = (2 lb HC/ton)(91 ton/hr)

= 182 lb/hr HC

QHC = 23.0 g/s HC

B.3.7 Summary of Emissions in the Alternatives

The calculated emission rates for the major pollutants in the various fuel use alternatives is given in Table B-1.

B.4 DISPERSION MODELING

Northeast Utilities (NUSCO) has performed extensive atmospheric dispersion modeling to assess the effects of the low-sulfur coal conversion at the Mt. Tom generating station. The NUSCO modeling exercise was performed in support of the application for the DCO. Part of the discussion below is taken from the description of the dispersion modeling procedures used presented by NUSCO in material submitted to EPA Region I in support of the DCO request.

The Clean Air Act (CAA) stipulates that a prerequisite for granting of a DCO be a demonstration that the primary ambient air quality standards are not jeopardized by the DCO action. (See Section 3.3.3 of the EIS for a detailed statement of the CAA requirements that apply to the Mt. Tom low-sulfur coal conversion.) It is this demonstration that was supplied by the NUSCO dispersion modeling effort. The modeling performed by NUSCO to meet the prerequisites of the DCO for the low-sulfur coal conversion was used to provide estimates of the air quality effects of a conversion to any of the alternative fuels. The estimate of impacts due to alternative fuel use was done in a conservative fashion, tending to overestimate air quality effects, to the extent possible.

At DOE's request Dames & Moore has reviewed in detail the dispersion modeling performed by NUSCO for the Mt. Tom low-sulfur coal conversion, and has also reviewed the correspondence between EPA Region I and NUSCO regarding a plethora of technical requirements for the NUSCO model. These technical requirements were largely concerned with dispersion modeling for high terrain locations near the Mt. Tom station, which is discussed below. Dames & Moore is of the opinion that the NUSCO modeling exercise is adequate to meet the assessment requirements of this EIS.

The detailed description of the NUSCO modeling effort is given in the NUSCO document entitled "Environmental Data and Impacts of Coal Burning at Mt Tom Generating Station" (September 1979) and in the Addendum I (December 1980) and Addendum II (March 1981) amendments to that document. The addenda were prepared by NUSCO in response to several

EPA Region I memoranda commenting on the technical requirements of the modeling exercise. The NUSCO documents were submitted in support of the DCO request, and are available in the public file for action on that request.

A significant complication in the dispersion modeling was the presence of "high terrain," that is, terrain considerably higher than the top of the Mt. Tom station stack, on Mount Nonotuck and Mount Holyoke near the station. There exists no general EPA-approved refined computer dispersion model appropriate for the calculation of pollutant concentrations on such high terrain. An EPA-approved screening model, VALLEY, predicted that operation of Mt. Tom station on 2.2 percent sulfur fuel oil (and, therefore, also on coal) would produce short-term SO_2 concentrations exceeding the national ambient air quality standards (NAAQS) on the nearby high terrain. Ambient measurement of SO_2 concentrations at the Summit House location on Mount Holyoke refuted the VALLEY calculations, thereby indicating that VALLEY produced unrealistic overestimates of the concentrations.

In order to demonstrate that the low-sulfur coal conversion would not jeopardize the NAAQS on the high terrain, it was necessary for NUSCO to show that the NUSCO refined model, called AQPGM, could adequately represent high terrain concentrations. This required a "validation" study of AQPGM, in which concentrations calculated by AQPGM were compared to measured SO_2 data at the Summit House location. NUSCO was successful in showing that AQPGM could realistically and conservatively calculate SO_2 concentrations on the higher terrain, based on modeling calculations compared with three years of measured SO_2 concentrations at the Summit House location. Following this demonstration, EPA Region I accepted the use of AQPGM to assess the effect of the Mt. Tom coal conversion on ambient concentrations on the high terrain.

B.4.1 Modeling Methodology

Three separate computer dispersion models were used to assess the effect of the low-sulfur coal conversion. These models, and their use in the assessment, were the following:

1) CRSTER. This is the "benchmark" EPA model for dispersion calculations in rural areas. It is a single-source model. CRSTER was used to calculate some concentrations due to the Mt. Tom station stack on terrain lower than the top of the stack.

2) ISC. This is an EPA multiple-source model, which may be used for a variety of source types and in either urban or rural settings. ISC was used to assess the total concentrations on low terrain due to interaction of other major sources in the area with the Mt. Tom station stack, and also to calculate concentrations due to Mt. Tom alone on lower terrain than the stack top elevation.

3) AQPGM. This is a single-source model developed by NUSCO, and validated as described above for calculation of concentrations on nearby high terrain due to emissions from the Mt. Tom station stack.

The meteorological data used in the modeling were taken from the onsite Mt. Tom generating station meteorological tower. These data consisted of hourly average values of wind speed and wind direction (measured to one degree resolution), ambient temperature, and derived Pasquill stability classes. The stability classes were calculated from measurements of the vertical gradient of temperature for nighttime hours, and from the standard deviation of the horizontal wind direction for daytime hours. Seasonal average values of the atmospheric mixing height with an hourly diurnal variation were used. The details of the choices used for the stability classification and the mixing heights were in accordance with recommendations by EPA Region I. The meteorological data record used in the modeling consisted of the data for 1977, 1978, and 1979.

The receptor grids used in the modeling varied according to the different models and the purpose of the particular model run:

- The CRSTER receptor grid consisted of a set of 5 concentric rings, of 36 receptors each, centered on the Mt. Tom stack. The ring distances were determined using the EPA screening model PTMAX according to the guideline procedure recommended by EPA Region I.

- The ISC receptor grid consisted of a 20 km by 20 km square grid with receptors separated by 1 km (a total of 440 receptors), centered on the Mt. Tom stack.

° The AQPGM initial receptor grid was identical to the ISC grid. A finer resolution grid, consisting of a 1 km square with receptor spacing of 200 m, was centered on the locations of the high terrain maximum and highest second maximum 24-hour and 3-hour concentrations (on the coarse grid) for each year of meteorological data. The finer resolution grids were used to precisely locate and determine the maximum calculated concentrations on the high terrain.

The modeling performed for the DCO assessment used the maximum 24-hour SO_2 emission rate for the Mt. Tom low-sulfur coal conversion. Concentrations for PM or for smaller SO_2 emission rates for coal burning were calculated without additional modeling by scaling the maximum SO_2 emission rate results by the ratio of the emission rate to the maximum SO_2 emission rate.

The Mt. Tom generating station was modeled under three different operating conditions for the short-term averaging times: 100 percent of capacity, 75 percent of capacity, and 50 percent of capacity. The worst calculated results from these operating conditions were used in the analysis. Both the ISC and the AQPGM models were run on the same receptor grid, and the highest concentration calculated by either model at each receptor point was used.

Other nearby major sources (those with emissions greater than 100 tons per year) were also included in the modeling exercise. These sources are exhibited in Table B-2. The nearby sources were modeled using ISC. The impacts of these other sources were then combined with the maximum impacts of Mt. Tom station. Spatial concurrence was attained by using the second highest impact of nearby sources at the point of the maximum second highest impact of Mt. Tom station alone. (Perusal of computer printouts verified that this yielded the highest overall concentrations.) Temporal concurrence was ignored.

The above procedure was followed for the 24-hour and 3-hour impacts for SO_2 and 24-hour impacts for PM (the 24-hr PM impacts for the station alone were simply ratioed from the 24-hr SO_2 impacts). For annual impacts all sources including Mt. Tom were modeled together using ISC. The annual average impacts are the maximum from all sources in the study and the maximum from Mt. Tom alone, without regard to spatial or temporal concurrence.

The modeled SO_2 impacts of sources other than Mt. Tom are higher than would actually be expected. This is due to the fact that Riverside and MMWEC were modeled at design capacity for all averaging times, a situation which in reality does not occur for either long or short term periods. Even with this unrealistically conservative approach, ambient air quality standards are shown not to be violated.

Before the modeled impacts can be compared to the NAAQS, they must be added to appropriate background concentrations. Ideally, these concentrations should reflect the pollutant loading in a given area under specific meteorological conditions, without any influence from local sources. The stack base SO_2 monitor at Mt. Tom station fits this description reasonably well. While there are several other monitors in area, they are all subject to significant influence from nearby sources of SO_2. The use of these sites as background monitors would lead to double counting, since all major SO_2 sources were included in the modeling analysis. Therefore, the second-high running average at the stack base monitor was used for 3-hour and 24-hour background levels, and the annual average from this monitor was used as the annual background concentration.

Unfortunately, there is no such ideally located particulate matter monitor in the study area. The highest second-high 24-hour reading taken anywhere in the area was 185 $\mu g/m^3$ at the Howard School in Springfield. In lieu of a better estimate, this value of 185 $\mu g/m^3$ was used as an area-wide 24-hour background. An examination of annual PM concentrations revealed one site (the Chicopee trailer) that is over the primary standard. However, this site is suspect and most likely is not representative of the study area (the Massachusetts DEQE has not declared the area to be nonattainment for the primary standard). Other than this site, the annual average PM data taken in Holyoke, Springfield, and Chicopee show a remarkable consistency over 1977, 1978, and 1979. The measurements cluster around 60 $\mu g/m^3$, with the highest value being 63 $\mu g/m^3$ in Springfield in 1978. An annual background concentration of 63 $\mu g/m^3$ was used.

Measured background concentrations of NO_2, CO, and Pb are even less representative of the area affected by the Mt. Tom station, because these are strongly affected by local and transportation sources in the urban/industrial areas where these monitors are located. The closest monitor observations were used to represent background concentrations, but this is expected to be extremely conservative for the area actually affected by the Mt. Tom station contributions. The NO_2, CO, and Pb background concentrations were taken from observations in Springfield. No modeling of other source contributions to NO_2, CO, and Pb concentrations was performed.

The Mt. Tom station NO_2, CO, and Pb concentrations were estimated from the SO_2 modeling results by multiplying the SO_2 concentrations by the ratio of the other pollutant emissions to the SO_2 emissions. Differences in the averaging times from those for which the SO_2 concentrations were calculated were taken into account by the use of the following relationship between concentrations and averaging times.

$$C_T = C_o \left(\frac{T_o}{T}\right)^b$$

where: T_o is the basis averaging time
C_o is the concentration for averaging time T_o
T is the new averaging time
C_T is the concentration for averaging time T
b is equal to 0.20 for average conditions, and to 0.35 for worst-case short-term conditions (Ledbetter, 1972).

This relationship was used to estimate 1-hour and 8-hour CO concentrations from the 3-hour modeled values ($b = 0.35$) and to estimate the calendar quarter Pb concentration from the annual average value ($b = 0.20$).

Pb emissions were estimated by assuming that the coal will have a concentration of 25 ppm Pb by weight, and that all of the Pb content of the coal will be emitted from the stack.

B.4.2 Low-sulfur Coal Conversion

The highest concentrations calculated in the area for operation of Mt. Tom generating station under this scenario are presented in Table B-3 for the DCO period, and in Table B-4 for permanent operation subsequent to the DCO period. The concentrations for NO_2, CO, and Pb are given only in Table B-4, because the DCO has no effect on these pollutant emissions.

The DCO requires that ambient concentrations during the DCO period not exceed the primary ambient air quality standards. Table B-3 indicates that the low-sulfur coal conversion at Mt. Tom station would satisfy this requirement. The indicated total ambient concentrations are conservatively estimated, because they are estimated by the superposition of concentrations that were calculated at different locations or under different meteorological conditions. Also, the highest 24-hour Mt. Tom contribution was calculated under operating conditions of 50 percent load at the generating station, a condition that very rarely occurs at this base-load facility.

Because there exist measured exceedances of the ambient air quality standards for PM within AQCR 42, an additional prerequisite for a DCO is a rebuttal of regional limitation. This rebuttal must demonstrate that the DCO will not lead to significant exacerbation of existing violations of the ambient air quality standards. (See Section 3.3.3 of the EIS for a detailed description of the legislative requirements for this demonstration.) Table B-5 shows the calculated maximum contribution of the Mt. Tom generating station to the nonattainment area concentrations. Because the calculated contributions in Table B-5 are below the significance levels of 5.0 $\mu g/m^3$ for the 24-hour average and 1.0 $\mu g/m^3$ for the annual average, the DCO prerequisites concerning regional limitation are met, according to the guidelines issued by EPA Region I.

The modeling results for permanent (that is, subsequent to the DCO period) operation of Mt. Tom generating station under the low-sulfur coal conversion scenario are presented in Table B-4. The pertinent ambient air quality standards, which are identical for the national and Commonwealth of Massachusetts standards, are also presented for comparison. The total ambient concentration values given are conservative estimates as indicated above.

Examination of Table B-4 reveals total calculated ambient concentrations exceeding the standards for PM (secondary standards), for CO (8-hour standard), and for Pb. In each case, the standard is violated by the background contributions alone, irrespective of model calculations. Also, the Mt. Tom station contributions are smaller than the EPA minimum significant impacts for model calculations of PM and CO concentrations. These minimum significant impact levels for PM are 5 $\mu g/m^3$ for the 24-hour average and 1.0 $\mu g/m^3$ for the annual average (as previously mentioned), and for CO they are

500 μg/m^3 for the 8-hour average and 2,000 μg/m^3 for the 1-hour average. No significance level for modeling of Pb has been established, but note that the calculated Mt. Tom station contribution is smaller than the ambient standard by a factor of 500. Thus, it is demonstrated that the permanent operation of the Mt. Tom station under the low-sulfur coal conversion will not cause or significantly contribute to any violation of the ambient air quality standards.

The calculated maximum annual average contributions from Mt. Tom Station were located in relatively flat terrain approximately 2.2 km to the southeast of the stack. The 24-hour maxima were located in high terrain on the Holyoke Range approximately 2.2 km to the north-northeast of the Mt. Tom stack, and the 3-hour maximum was located in high terrain approximately 4.5 km to the east-northeast of the Mt. Tom stack.

The calculated ambient 24-hour SO_2 concentration of 364.7 μg/m^3 very closely approaches the primary ambient air quality standard of 365 μg/m^3. Given the conservative manner in which the calculated value was determined, this is not cause for concern. It does indicate that any alternative to the low-sulfur coal conversion that increases SO_2 ground-level concentrations may require a less conservative (and necessarily more extensive or more sophisticated) analysis than sufficed for the low-sulfur coal conversion.

B.4.3 No Action Alternative (Return to Oil Burning)

The no action alternative would be that no Notice of Effectiveness (NOE) to the ESECA prohibition order at Mt. Tom generating station be issued. For this discussion it is assumed that the station would return to oil fuel use. In comparison to the dispersion modeling results presented in Section B.4.2, this alternative makes little difference in the air quality effects.

Because of the reduced variability in fuel sulfur content, the maximum short-term (3-hour and 24-hour) SO_2 concentrations would be reduced from the low-sulfur coal conversion scenario by about 26 percent, but on the longer term (any averaging period equal to or greater than 30 days in length), the SO_2 impacts are approximately the same for both fuels. Short-term impacts using fuel oil are actually greater than 76 percent of the coal burning case because the exit velocity of stack gases is somewhat lower when firing oil compared to the exit gas velocity when firing coal. Because the effect of the difference in exit velocity should not be very large, and because its precise determination would require a modeling effort almost as great as was needed for the low-sulfur coal conversion analysis, this difference has been neglected in estimating the relative impacts shown in Table B-6.

This no action alternative would involve increased PM emissions and therefore increased PM concentrations as compared to the low-sulfur coal alternative following the DCO period. In Table B-6, the estimated concentrations are produced by multiplying the low-sulfur coal conversion analysis results by the appropriate ratio of emissions. It was assumed that the ratio of Pb emissions for fuel oil to coal is 0.0012.

B.4.4 Coal Conversion With Wet Scrubbing

The use of high-sulfur coal together with wet scrubber control technology could result in SO_2 emissions equal to those of the low-sulfur coal conversion, and that same emission rate is assumed here. However, another effect of a wet scrubber is to reduce the exit temperature of the stack plume, which in turn reduces the buoyant plume rise. This reduction in plume rise causes higher ground-level pollutant concentrations to occur, so that this alternative would have more severe air quality effects than will the proposed action.

Whenever wet scrubbing is used, it is usually necessary to reheat the exhaust gases leaving the scrubber in order to prevent condensation of sulfuric acid and resultant problems with corrosion. This reheating involves an energy penalty that strongly mitigates against reheating to the degree that would restore plume buoyancy to the level that would exist without the scrubber.

In order to estimate the approximate effect of the use of a wet scrubber in the Mt. Tom coal conversion, in comparison to the low-sulfur coal conversion results, it was assumed that the stack exit temperature would be reduced to 336°K (145°F), and that the SO_2 control efficiency would be 70 percent. These are fairly conservative estimates - larger exit temperatures and control efficiencies could be obtained by larger money and energy expenditures. Under neutral or unstable conditions, and a typical wind speed at stack height of 7 m/s, the reduced exit temperature would result in a final effective plume height approximately 25 percent lower than for the unscrubbed case. This plume rise reduction would in turn give rise to an increase in maximum ground-level concentrations by a factor of roughly 1.8.

For most of the important concentrations listed in Tables B-3 and B-4 for SO_2, PM, NO_2, CO, and Pb due to the low-sulfur coal conversion, there would be no significant change in the conclusions reached if the contribution from Mt. Tom were increased by 1.8 times. The exception is the 24-hour SO_2 ambient concentration during the DCO period, for which a Mt. Tom impact of 268 $\mu g/m^3$ would send the conservatively estimated total to 484 $\mu g/m^3$, considerably above the primary ambient air quality standard of 365 $\mu g/m^3$. This result does not mean that the use of a wet scrubber would necessarily produce unacceptable air quality effects. It does mean that if this alternative were eventually chosen for Mt. Tom generating station, careful design of the control system would be necessary in order to avoid (and to demonstrate avoidance of) violation of the pertinent ambient air quality standard.

B.4.5 Coal Conversion with Dry Scrubber

As was indicated above for wet scrubbers, the use of dry scrubbers will also lead to cooling of the stack plume, with subsequent reduction in buoyant plume rise. The precise amount of cooling that occurs, the amount of reheat necessary to avoid corrosion, and the amount of reheat economically feasible to use to increase plume buoyancy, are all sensitive to the details of the system design and operation. In the absence of the detailed engineering analysis that would be required to realistically estimate the effect of a dry scrubber system it was assumed that its air quality effects would not be significantly different from those of the wet scrubber described in B.4.4.

B.4.6 Coal Conversion with RDF

As indicated in Section B.3, the coal plus 20 percent RDF scenario will result in lowered (or the same) emissions of all criteria pollutants, except for CO and hydrocarbons (HC), in comparison to the low-sulfur coal conversion. Thus, except for CO, all the air quality effects modeled for the low-sulfur coal conversion case would be ameliorated if 20 percent RDF were burned at Mt. Tom generating station. And although the CO emissions rate would be 20 times larger than in the low-sulfur coal conversion case, the resulting Mt. Tom contributions would still be insignificant in comparison to the CO ambient air quality standards.

As indicated in Section B.3, the dispersion of unregulated toxic materials in extremely small concentrations might be the primary air quality effect of the use of RDF. It is assumed that the Pb content of the RDF is equal to that of coal.

B.4.7 Conversion to Wood Chips Fuel

For this scenario, it was assumed that there would be no DCO and no SIP change, and that the PM emissions would remain limited to the fossil fuel limitation of 0.12 lb PM/10^6 Btu heat production.

The combustion of wood results in a drastic reduction of SO_2 emissions when compared to the low-sulfur coal conversion. PM concentrations could be expected to remain nearly the same as for the oil burning alternative. Substantial increases in CO concentrations (by about a factor of 3) could be expected, but these would still be insignificant in comparison to the ambient air quality standards.

Perhaps the major air quality effect of wood burning at Mt. Tom would be an increase in regional ozone concentrations due to the very substantial increase in HC emissions that would result.

B.4.8 Summary of Calculated Impacts

The estimated maximum Mt. Tom generating station contributions to ambient concentrations are summarized in Table B-6. The concentrations for the alternative fuel use scenarios were calculated by multiplying dispersion model results obtained for the low-sulfur coal conversion analysis by the ratio of emissions between the alternative and low-sulfur scenarios. An exception was made for the scenario in which scrubbers are posited together with high-sulfur coal. In this case the concentrations were increased by a factor of 1.8 to take account of reduced buoyant plume rise, as described in Section B.4.4.

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TABLE B-1

MT. TOM GENERATING STATION STACK EMISSIONS OF MAJOR POLLUTANTS (g/s)

	Fuel Use Scenario				
Pollutant	No Action[a]	Low-sulfur Coal Conversion	High-sulfur Coal Plus SO_2 Scrubbing	Coal Conversion Plus 20% RDF	Wood as Primary Fuel
SO_2	400	397 (30-day) 525 (24-hr)	397 (30-day) 525 (24-hr)	326 (30-day) 428 (24-hr)	17.3
PM	20.9[b]	82.9 (DCO period) 13.8 (permanent)	82.9 (DCO period) 13.8 (permanent)	82.9 (DCO period) 13.8 (permanent)	20.7
NO_2	66.5[c]	124	124	110	115
CO	5.9	6.9	6.9	126	23.0
HC	1.2	2.1	2.1	6.8	23.0

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[a] Assumes a return to oil burning.

[b] Assumes that the currently existing PM control systems reduce PM emissions to the allowed value of 0.12 lb PM/10^6 Btu heat input.

[c] According to stack test results reported in NUSCO, 1981.

TABLE B-2

NEARBY MAJOR SOURCES[a] IN THE VICINITY OF MT. TOM

Name of Source	Location (from Mt. Tom) Distance (km)	Location (from Mt. Tom) Direction (deg)	Annual SO_2 Emissions (typ)	Annual PM Emissions (typ)	Present Percent Sulfur	Maximum SO_2 Emission Rate (g/sec)[b]
University of Massachusetts	13.7	25.4	811.9	919	1.0[c]	24.5
Amherst College	12.8	35.4	233.4	<100	2.2	6.7
Smith College	4.5	319.5	328.1	<100	2.2	12.3
Mt. Holyoke College	4.3	139.7	166.8	<100	2.2	4.8
James River Graphics	7.0	170.1	432.9	<100	2.2	13.0
Lineweave	8.4	171.8	378.7	<100	2.2	19.0
Gas and Electric Company	9.0	181.3	260.0	<100	1.0	7.5
Uniroyal	14.2	171.9	541.4	<100	2.2	15.6
Monsanto	15.2	150.4	1,269.5	142.6	2.2	36.4
Riverside	8.9	175.5	2,900[d]	<100	1.0	83.5[d]
Belchertown State School	15.6	89.3	100.0	<100	1.0	2.9
MMWEC	16.4	148.7	6,900[d]	1,110	0.3	198.3[d]

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[a] Nearby major source in this context means any source greater than 100 tpy actual emissions and closer than 20 km to the Mt. Tom plant.

[b] Calculated from the annual SO_2 emissions divided by the annual hours of operation.

[c] 1.0% is for either coal or oil.

[d] Design capacity emissions.

TABLE B-3

CALCULATED AIR QUALITY EFFECTS IN THE MT. TOM STATION AREA FOR POLLUTANT EMISSIONS DURING THE DCO PERIOD UNDER THE LOW-SULFUR COAL CONVERSION. COMPARISON WITH PRIMARY AMBIENT AIR QUALITY STANDARDS

(Concentrations given in μ g/m^3)

Pollutant	Averaging Time	Modeled Mt. Tom DCO Contribution	Modeled Other Source Contribution	Measured Background	Total Calculated Ambient Concentration	Primary Ambient Air Quality Standard
SO_2	24-hr	149.1	76.7	138.9	364.7	365
	Annual	3.0	21.3	32	56.3	80
PM	24-hr	22.4	7.1	185	214.5	260
	Annual	0.6	3.1	63	66.7	75

TABLE B-4

CALCULATED AIR QUALITY EFFECTS IN THE MT. TOM STATION AREA FOR PERMANENT OPERATION UNDER THE LOW-SULFUR MOU COAL CONVERSION. COMPARISON WITH AMBIENT AIR QUALITY STANDARDS

(Concentrations given in μg/m^3)

Pollutant	Averaging Time	Modeled Mt. Tom Contribution	Modeled Other Source Contribution	Background	Total Calculated Ambient Concentration	Ambient Air Quality Standards	
						Primary	Secondary
SO_2	3-hr	241	166	276	683	--	1,300
	24-hr	149.1	76.7	138.9	364.7	365	--
	Annual	3.0	21.3	32	56.3	80	--
PM	24-hr	3.7	7.1	185	195.8	260	150
	Annual	0.1	3.1	63	66.2	75	60
NO_2	Annual	0.9	--	85	85.9	100	100
CO	1-hr	4.7	--	19,480	19,485	40,000	40,000
	8-hr	2.3	--	11,920	11,922	10,000	10,000
Pb	Calendar Quarter	0.003	--	2.9	2.9	1.5	1.5

TABLE B-5

CALCULATED YEARLY MAXIMUM PM CONTRIBUTIONS DUE TO THE DCO-ALLOWED MT. TOM STACK EMISSIONS AT NONATTAINMENT MONITOR LOCATIONS IN AQCR 42

(Concentrations in $\mu g/m^3$)

Location	Averaging Period	1977	1978	1979
Chicopee (939 Chicopee St.)	Annual	0.18	0.21	0.20
	24-hr	1.88	2.47	2.48
Waterbury (DOT Entrance to I-84)	Annual	0.11	0.12	0.12
	24-hr	1.53	1.13	1.81
Waterbury (Waste Treatment Plant)	Annual	0.11	0.11	0.11
	24-hr	1.41	1.01	1.69
New Haven (677 State St.)	Annual	0.12	0.18	0.14
	24-hr	1.11	1.12	1.34

TABLE B-6

ESTIMATED MAXIMUM MT. TOM GENERATING STATION CONTRIBUTIONS TO AMBIENT CONCENTRATIONS FOR ALTERNATIVE FUEL USE SCENARIOS
(Concentrations in μ g/m^3)

Pollutant	SO_2			PM		NO_2		CO		Pb
Averaging Time:	3-Hr	24-Hr	Annual	24-Hr	Annual	1-Hr[a]	Annual	1-hr	8-hr	Calendar Quarter
MOU Coal Conversion										
DCO Period	241	149	3.0	22.4	0.6	84	0.9	4.7	2.3	0.003
Permanent Operation	241	149	3.0	3.7	0.1	84	0.9	4.7	2.3	0.003
No Action (Continued Fuel Oil)[b]	184	114	3.0	5.6	0.2	46	0.5	4.0	2.0	0.0004
High Sulfur Coal with Scrubbing[c]										
DCO Period	434	268	5.4	40.3	1.1	151	1.6	8.5	4.1	0.005
Permanent Operation	434	268	5.4	6.7	0.2	151	1.6	8.5	4.1	0.005
Coal Conversion with 20% RDF										
DCO Period	196	121	2.5	22.4	0.6	75	0.8	84.8	40.1	0.003
Permanent Operation	196	121	2.5	3.7	0.1	75	0.8	84.8	40.1	0.003
Wood Chips as Primary Fuel[d]	8	5	0.1	5.8	0.2	78	0.8	15.7	7.7	--

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[a] The 3-hour NO_2 concentration has no regulatory status. It is used here merely to be representative of short-term NO_2 ambient effects.

[b] For estimation of the maximum PM concentrations, the Mt. Tom station PM emission rate was assumed to be the permitted limit of 0.12 lb/10^6 Btu (20.9 g/s) rather than the measured value of 0.046 lb/10^6 Btu (8.0 g/s) obtained by stack testing.

[c] Reduced buoyant plume rise compared to the MOU conversion is assumed to increase concentrations by a factor of 1.8.

[d] It is assumed that the stack exit characteristics for wood burning are the same as for coal burning. This would unlikely be true, but engineering data to support any other assumption are unavailable.

APPENDIX C

FEDERAL PERMITS/APPROVALS

CONTENTS

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM PERMIT

DELAYED COMPLIANCE ORDER

STATE IMPLEMENTATION PLAN REVISION

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM PERMIT

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION I

J. F. KENNEDY FEDERAL BUILDING, BOSTON, MASSACHUSETTS 02203

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

RECEIVED

DEC 7, 1981

SENIOR VICE PRESIDENT
Nuclear Engineering & Operations

December 1, 1981

Mr. W. G. Counsil
Senior Vice President
Northeast Utilities Service Co.
P.O. Box 270
Hartford, CT 06101

Re: NPDES Application No. MA0005339
Holyoke Water Power Company
Mt. Tom Station

Dear Mr. Counsil:

Enclosed is the National Pollutant Discharge Elimination System (NPDES) permit for the above referenced facility, issued pursuant to Section 402 of the Clean Water Act (the "Federal Act"), as amended and Chapter 21, Sections 43-45 of the Massachusetts Clean Waters Act (the "State Act"), as amended. This action constitutes issuance of a final permit under Title 40, Code of Federal Regulations, Section 124.15, 45 Fed. Reg. 33490 (May 19, 1980). The Agency is required to respond to all significant comments received on the draft permit. If significant comments were received relative to this permit, a response has been prepared and is available for viewing between the hours of 9:00 a.m and 5:00 p.m., Monday thru Friday, except holidays, at the Permits Branch, Environmental Protection Agency, John F. Kennedy Federal Building, Room 2109, Boston, MA 02203.

Pursuant to 40 C.F.R. §124.15, under the Federal Act, this permit shall become effective on the effective date specified in the permit. Under State law, the permit shall become effective 30 days from receipt. Should EPA receive and grant a request for a formal hearing, for existing sources the contested provisions of the permit will be stayed and will not become effective until the administrative review process is completed, in accordance with 40 C.F.R. §124.60. All uncontested provisions of the permit will be effective and enforceable in accordance with the provisions of 40 C.F.R. §124.60 (c)(5). However, if your facility has been determined to be a new source, new discharger, or recommencing discharger, you shall be without a permit pending final agency action.

Any request for a formal hearing under Federal law must conform to the requirements of 40 C.F.R. §124.74 (b) and (c), a copy of which is enclosed. An original and two copies of all such requests should be submitted to the Regional Hearing Clerk, within 30 days of receipt of this letter, as follows:

Regional Hearing Clerk
U. S. Environmental Protection Agency
Enforcement Division
John F. Kennedy Federal Building
Room 2103
Boston, MA 02203

A copy of the final permit for your facility is being forwarded to the Director by copy of this letter.

Should you have any questions relative to the hearing process, please contact our Enforcement Branch at 617/223-5470.

Sincerely,

John R Moebes

John R. Moebes, Chief
Permits Branch

Enclosures

cc: Massachusetts Division of Water Pollution Control
All Interested Parties (w/o enclosures)

The Commonwealth of Massachusetts
Executive Office of Environmental Affairs
Department of Environmental Quality Engineering
Division of Water Pollution Control
ONE Winter Street, Boston 02108

ANTHONY D. CORTESE, Sc. D.
Commissioner

November 27, 1981

W.G. Counsil
Senior Vice President
Northeast Utilities
Post Office Box 270
Hartford, Connecticut 06101

Re: NPDES Permit No. MA005339,
State Permit No. 278-
Holyoke Water Power Company
Mt. Tom Generating Station

Dear Mr. Counsil:

Enclosed is the original signed copy of the joint NPDES discharge permit referenced above issued by this Division and EPA to Holyoke Water Power Company for its Mt. Tom Generating Station. This permit has been issued pursuant to the Massachusetts Clean Waters Act, M.G.L.c.21, s.s. 26 through 53, and is effective upon issuance under Massachusetts law.

In issuing this permit, the Division finds that it has used all feasible means and measures to avoid or minimize damage to the environment from this project. This finding is based on the environmental impact of this project as described in the final environmental impact report prepared for this project and noticed in the Environmental Monitor of September 22, 1981, EOEA Number 4152, and also on the permit application and information submitted to the Division in support thereof.

Parties aggrieved by the issuance of this permit are hereby advised of their right to request an adjudicatory hearing in accordance with the provisions of G.L. c.30A and the "Standard Adjudicatory Rules of Practice and Procedure, Formal Rules" codified at 801 CMR 1.01. Parties may request a hearing by filing a written Notice of Claim with the Director at the above address within twenty-one days of the issuance of this permit pursuant to 801 CMR 1.01(6). The Notice of Claim must state clearly and concisely the facts which are grounds for the claim and the relief sought. The Party filing the request, and his attorney, if any, shall indicate their complete name, address and telephone number. The filing of a notice of claim will not automatically stay the effectiveness of this permit.

Inasmuch as the permittee and the Division are the only parties to the State permit, all other persons desiring to file a claim for an Adjudicatory Hearing in this matter must, in addition to complying with the contents of the claim outlined above, file a written petition for leave to intervene in this proceeding in accordance with 801 CMR 1.01(9). The form and content of the petition are prescribed in 801 CMR 1.01(9).

Very truly yours,

Thomas C. McMahon

Thomas C. McMahon
Director

TCM/GAF/wp

The Commonwealth of Massachusetts
Executive Office of Environmental Affairs
Department of Environmental Quality Engineering
Division of Water Pollution Control
ONE Winter Street, Boston 02108

ANTHONY D. CORTESE, Sc. D.
Commissioner

November 27, 1981

John Moebes, Chief
Permits Branch
U.S. Environmental Protection Agency
John F. Kennedy Building
Boston, Massachusetts 02203

Re: Water Quality Certification
NPDES Permit MA0005339
Holyoke Water Power Company
Mt. Tom Station, Holyoke

Dear Mr. Moebes:

Your office has requested this Division to issue a water quality certification pursuant to Section 401(a) of the Federal Clean Water Act ("the Federal Act") and 40 CFR 124.53 for the above-referenced NPDES permit. The Division has reviewed the final permit, attached hereto, and has determined that the permit conditions assure compliance with sections 208(e), 301, 302, 303, 306 and 307 of the Federal Act, and with the provisions of the Massachusetts Clean Waters Act, M.G.L.c.21, ss 26-53 ("the State Act") and regulations promulgated thereunder.

The Division therefore and hereby certifies the referenced permit. None of the conditions of the permit may be made less stringent without violating the requirements of the State Act and the Massachusetts Water Quality Standards.

In addition to enclosing the original of the final permit signed by this Division, we are enclosing a signed cover letter to accompany the joint final permit for mailing to the permittee. This cover letter explains the rights of parties to request an adjudicatory hearing of the Division relative to this permit, and makes certain findings required under Massachusette law. Copies of the final permit and state cover letter should be mailed to the persons indicated at the end of the cover letter.

Very truly yours,

Thomas C. McMahon

Thomas C. McMahon
Director

TCM/WAS/wp
Enclosures

cc: Alexandra D. Dawson, Esq., Mountain Farms Mall, Route 9, Hadley 01035

State Permit No. 278
Federal Permit No. MA0005339
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Reissuance

AUTHORIZATION TO DISCHARGE UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provisions of the Federal Clean Water Act, as amended, (33 U.S.C. §§1251 et seq.; the "CWA"), and the Massachusetts Clean Waters Act, as amended, (M.G.L. Chap. 21, §§26-53),

Holyoke Water Power Company

Mount Tom Station

is authorized to discharge from the facility located at

Route 5, Smith's Ferry
Hampden County
Holyoke, MA 01040

to receiving waters named

Connecticut River

in accordance with effluent limitations, monitoring requirements and other conditions set forth herein.

This permit shall become effective on December 1, 1981.

This permit and the authorization to discharge expire at midnight, five years from effective date.

This permit supersedes the permit issued on January 8, 1980.

This permit consists of 15 pages in Part I including effluent limitations, monitoring requirements, etc. and 19 pages in Part II including General Conditions and Definitions.

Signed this 30 day of November, 1981

Lawrence M. Goldman
Acting Director, Enforcement Division
Environmental Protection Agency
Region I
Boston, MA

Thomas C. McMahon
Director, Division of Water
Pollution Control
Department of Environmental
Quality Engineering
Commonwealth of Massachusetts
Boston, MA

A. Effluent Limitations and Monitoring Requirements

1. Except as specified in Paragraphs 1 through 7 herein, the permittee shall not discharge to Connecticut River, a final effluent to which it has added any pollutants.

   a. Chlorine may be used as a biocide. No other biocide shall be used without explicit approval from the Regional Administrator and the Director. The chlorination cycle shall not exceed two hours in any one day for any one unit and not more than one unit shall be chlorinated at any one time.

   b. Total Residual Chlorine concentration shall be measured downstream of the unit being chlorinated before that stream mixes with any other discharge.

   c. The discharges shall not jeopardize any Class B use of the Connecticut River and shall not violate applicable water quality stantards.

   d. Solids (not including aquatic organisms, leaves, or weeds) collected on the intake racks and screens shall not be reintroduced into the Connecticut River. The fish screen shall be in operation whenever there is cooling water flow.

   e. This permit shall be modified, or alternatively, revoked and reissued to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2), and 307(a)(2) of the Act, if the effluent standard or limitation so issued or approved:

      (1) contains different conditions or is otherwise more stringent than any effluent limitation in this permit; or

      (2) controls any pollutant not limited by this permit.

   If the permit is modified or reissued, it shall be revised to reflect all currently applicable requirements of the Act.

   f. The term "Regional Administrator" means the Regional Administrator of Region I of the U.S. Environmental Protection Agency and the term "Director" means the Director of the Division of Water Pollution Control of the Massachusetts DEQE.

   g. It has been determined based on engineering judgment that the circulating water intake structure presently employs the best technology available for minimizing adverse environmental impact. Any change in the location, design or capacity of the present structure shall be approved by the Administrator and the Director. The present design shall be reviewed for conformity to regulations pursuant to Section 316(b) of the Act when such are promulgated.

h. Combined thermal plumes for the station shall: (a) not block the zone of fish passage, (b) not interfere with spawning of the indigenous population, (c) not change the balanced indigenous population of the receiving water, and (d) have minimal contact with surrounding shorelines.

i. The combined thermal plumes from the station shall not interfere with the Atlantic Salmon Restoration Program.

j. There shall be no discharge of polyclorinated biphenyl compounds such as those commonly used for transformer fluid.

k. All existing manufacturing, commercial, mining, and silvicultural dischargers must notify the Director as soon as they know or have reason to believe:

   (1) That any activity has occurred or will occur which would result in the discharge of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

      (a) One hundred micrograms per liter (100 ug/l);

      (b) two hundred micrograms per liter (200 ug/l) for acrolein and acrylonitrile; five hundred micrograms per liter (500 ug/l) for 2,4-dinitrophenol and for 2-methyl-4,6-dinitrophenol; and one milligram per liter (1 mg/l) for antimony;

      (c) five (5) times the maximum concentration value reported for that pollutant in the permit application or;

      (d) any other notification level established by the Director in accordance with 40 C.F.R. §122.62(f).

   (2) That they have begun or expect to begin to use or manufacture as an intermediate or final product or byproduct any toxic pollutant which was not reported in the permit application.

PART I

A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

2. During the period beginning effective date and lasting through expiration date, the permittee is authorized to discharge from outfall(s) serial number(s) 001, Condenser Cooling Water an effluent that shall not exceed the following conditions.

   a. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitaitons				Monitoring Requirements	
	kg/day (lbs/day)		Other Units(Specify)		Measurement	Sample
	Avg. Monthly	Max. Daily	Avg. Monthly	Max. Daily	Frequency	Type
Flow-m^3/Day (MGD)	-	-	133.2MGD	133.2MGD	Hourly*	Daily Average & Ran
Total Residual Chlorine			0.1mg/1	0.1**mg/1	Weekly when in use	Grab

   b. The temperature of the discharge shall at no time exceed a 32°F rise over the temperature of intake but also at no time exceed a maximum of 102°F. Temperature shall be monitored continuously for the daily average and range.

   c. The pH shall not vary more than 0.5pH standard units from that of natural river water and shall be monitored weekly by a grab sample.

   d. There shall be no discharge of visible oil sheen, foam, or floating solids in other than trace amounts.

   e. Samples taken in compliance with the monitoring requirements specified above shall be taken at a representative point prior to the point of discharge into the Connecticut River.

   * Flow rate to be estimated from pump capacity curves and pump operational hours.

   ** Chlorine Management Program:

   1. Total Residual Chlorine shall not exceed a maximum instantaneous concentration of 0.1 mg/l. In the event that the units cannot be operated at or below this level of chlorination, the permittee may submit a demonstartion showing that the discharge of higher levels of chlorine are consistent with the toxicity requirements of the Massachusetts Water Quality Standards based upon:
      biological toxicity data, live organism toxicity tests, chlorine versus temperature toxicity relationship, or plant operational data.

2. If a demonstration is to be made, the permittee shall submit within 60-days after the effective date of this permit to the Director and the Regional Administrator for approval a continued plan for the chlorine management study to determine the minimum level of chlorine discharge into the Connecticut River while maintaining a suitable condenser efficiency.

3. Until the demonstration has been completed and approved by the Director and the Enforcement Director or until permit termination, whichever comes first, the Free Available Chlorine concentration from the discharge of the unit being treated shall not exceed 0.1 mg/l on an average or exceed an instantaneous maximum of 0.2 mg/l.

4. The chlorine management program final report shall be submitted to the Regional Administrator and the Director by July 1, 1983. This report is to incorporate the data obtained under the expired permit and under this permit.

A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

3. During the period beginning effective date and lasting through expiration date, the permittee is authorized to discharge from outfall(s) serial number(s) 004 yard drains, 005 traveling screen wash, 007 oil trap overflow and highway runoff, an effluent that shall not exceed the following conditions.

a. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitaitons				Monitoring Requirements	
	kg/day (lbs/day)		Other Units(Specify)		Measurement	Sample
	Avg. Monthly	Max. Daily	Avg. Monthly	Max. Daily	Frequency	Type
Flow						
004				29,000GPD	Estimate*	
005				374,000GPD	Estimate	Daily Avg. & Range
007				10,000GPD	Estimate	Daily Avg. & Range
Total Suspended Solids (007 only)			30.0 mg/1	100.0 mg/1	Monthly	Grab
Oil and Grease (004 and 007 only)				15.0 mg/1	Monthly	Grab

* Intermittant flow during rainstorms. Estimate typical storm rainfall in inches per day and maximum flow rate expected from discharge 004 in gallons per day.

b. The pH shall not be less than 6.5 standard units nor greater than 8.0 standard units and shall be monitored monthly by a grab sample for discharge 007 only.

c. There shall be no discharge of floating solids for discharges 004 and 005 or visible foam in other than trace amounts.

d. Samples taken in compliance with the monitoring requirements specified above shall be taken at any representative point prior to the point of discharge into the Connecticut River.

e. For discharge 007, the samples taken in compliance with the monitoring requirements shall be taken at the oil trap overflow.

Pa. . I

A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

4. During the period beginning effective date and lasting through expiration date, the permittee is authorized to discharge from outfall(s) serial number(s) 002 Waste Water Treatment System, an effluent that shall not exceed the following conditions.

a. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitaitons				Monitoring Requirements	
	kg/day (lbs/day)		Other Units(Specify)		Measurement Frequency	Sample Type
	Avg. Monthly	Max. Daily	Avg. Monthly	Max. Daily		
Flow-m^3/Day (MGD)	-	-	0.11	0.13	Daily	Daily Avg. & Range
Suspended Solids			30.0 mg/1	100.0 mg/1	Biweekly*	Grab
Total Copper			1.0 mg/1	1.0 mg/1	"	"
Total Iron			1.0 mg/1	1.0 mg/1	"	"
Total Nickel			1.0 mg/1	2.0 mg/1	"	"
Total Zinc			1.0 mg/1	2.0 mg/1	"	"
Oil and Grease				15.0 mg/1	"	"

* Biweekly is defined as one sample every two weeks.

b. The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored biweekly.

c. There shall be no discharge of floating solids or visible foam in other than trace amounts.

d. Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at any representative point prior to the point of discharge to the Connecticut River.

P. I

A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

5. During the period beginning effective date and lasting through expiration date, the permittee is authorized to discharge from outfall(s) serial number(s) 010 and 011 Fly Ash Settling Basin, an effluent that shall not exceed the following conditions.

a. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitaitons				Monitoring Requirements	
	kg/day (lbs/day)		Other Units(Specify)			
	Avg. Monthly	Max. Daily	Avg. Monthly	Max. Daily	Measurement Frequency	Sample Type
Flow-m^3/Day (MGD)	-	-	1.0	1.2 MGD	Daily	Daily Avg. & Range
Suspended Solids			30.0 mg/1	100.0 mg/1	Biweekly	Grab
Total Copper			1.0 mg/1	1.0 mg/1	"	"
Total Iron			1.0 mg/1	1.0 mg/1	"	"
Total Nickel			1.0 mg/1	2.0 mg/1	"	"
Total Zinc			1.0 mg/1	2.0 mg/1	"	"
Oil and Grease				15.0 mg/1	"	"

b. The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored biweekly.

c. There shall be no discharge of floating solids or visible foam in other than trace amounts.

d. Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at any representative point prior to the point of discharge to the Connecticut River.

A. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

6. During the period beginning effective date and lasting through expiration date, the permittee is authorized to discharge from outfall(s) serial number(s) 008 and 009 Bottom Ash Settling Basin, an effluent that shall not exceed the following conditions.

   a. Such discharges shall be limited and monitored by the permittee as specified below:

Effluent Characteristic	Discharge Limitaitons				Monitoring Requirements	
	kg/day (lbs/day)		Other Units(Specify)		Measurement	Sample
	Avg. Monthly	Max. Daily	Avg. Monthly	Max. Daily	Frequency	Type
Flow-m³/Day (MGD)	-	-	0.25 MGD	0.30 MGD	Daily	Daily Avg. & Range
Suspended Solids			30.0 mg/1	100.0 mg/1	Biweekly	Grab
Total Copper			1.0 mg/1	1.0 mg/1	"	"
Total Iron			1.0 mg/1	1/0 mg/1	"	"
Total Nickel			1.0 mg/1	2.0 mg/1	"	"
Total Zinc			1.0 mg/1	2.0 mg/1	"	"
Oil and Grease				15.0 mg/1	"	"

   b. The pH shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored biweekly.

   c. There shall be no discharge of floating solids or visible foam in other than trace amounts.

   d. Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location(s): at any representative point prior to the point of discharge to the Connecticut River.

7. Discharge 006, Reflecting Pond Overflow, Effluent Limitations

This discharge is classified as a non-contaminated reflecting pool overflow. There shall be no pollutants added to this discharge by the permittee. This discharge may be released without numerical limitation or monitoring and reporting requirements.

8. Coal Conversion Test Program

(1) The permittee shall submit to the Regional Administrator and the Director a test program for evaluating the chemical composition of the following liquid and solid streams after conversion to coal as a fuel:

(a) Coal as received.
(b) Bottom Ash.
(c) Fly Ash.
(d) Bottom Ash Sluice Water into and out of sedimentation basins.*
(e) Fly Ash Sluice Water into and out of sedimentation basins.*
(f) Fresh Water used for Sluicing.
(g) Coal Pile Runoff after a rain storm.
(h) Discharge from Special Waste and Equalization Basins.*
(i) Waste Water Treatment System discharge to Connecticut River.*

* If no discharge from the basins, a sample of the basin contents is adequate.

(2) The streams (subparagraph (1) above) shall be sampled twice simultaneously by grab samples on two different days when the facility is burning the new source coal.* The stream analysis shall include the following parameters where applicable but are not to be limited to:

(a) Flow rate (gpd or lbs/day)
(b) Total suspended solids
(c) Total dissolved solids
(d) pH
(e) BOD
(f) COD
(g) TOC
(h) Antimony (total)
(i) Arsenic (total)
(j) Beryllium (total)
(k) Cadmium (total)
(l) Chromium (total)
(m) Copper (total)
(n) Lead (total)
(o) Mercury (total)
(p) Nickel (total)
(q) Selenium (total)
(r) Silver (total)
(s) Thallium (total)
(t) Zinc (total)
(u) Iron (total)
(v) Manganese (total)
(w) Nitrate
(x) Sulfate

* When significantly different coal types or sources are used, the tests described in this paragraph may be repeated for the new coal being used at the discretion of the Regional Administrator or the Director.

(3) The metals shall be reported both as stream concentration and the pounds per day in that stream. The analytical procedures for each parameter shall be identified in the test plan for approval by the Regional Administrator and the Director.

(4) The test program must be submitted within 30 days after the effective date of the permit issuance. The samples are to be taken within 60 days after the facility is in stable operation using only the new source coal.

(5) The permittee shall provide in the test program the anticipated coal procurement plans with proposed coal sources.

(6) The permittee shall provide proposed plans for mitigating any coal pile runoff, sedimentation basin, holding basin, or equalization basin impacts to the ground water at the facility as detected by the test program in the Memorandum of Understanding between the Commonwealth of Massachusetts and the Holyoke Water Company dated March 6, 1980 (Attachment A). One copy of all reports derived from this hydrologic study shall be submitted to the Regional Administrator. The final report will be provided after approximately one year of burning coal (June 1, 1983) in accordance with the Memorandum of Understanding with any mitigating techniques deemed necessary.

9. **Biological Monitoring**

No biological monitoring is required. Future monitoring may be required, however, upon permit reissuance. Any unusual incidence of fish entrapment shall be reported to the Regional Administrator and the Director Immediately by telephone report. A written confirmation report is to be provided within 30 days. These reports should include the following:

a. The kinds, sizes and approximate number of fish entrapped.

b. The time and date of the occurrance.

c. The operating mode of the plant at the time of the occurrance.

d. The opinion of the company as to the reason that the entrapment occurred.

B. SCHEDULE OF COMPLIANCE

1. The permittee shall achieve compliance with the effluent limitations and/or conditions specified for discharges in accordance with the following schedule:

The permanent Waste Water Treatment Facility schedule is as follows:

a.	Preliminary Design and Drawings	January 29, 1982
b.	Final Design and Drawings	April 30, 1982
c.	Start Construction	May 28, 1982
d.	In Service Date	October 29, 1982

Note: The effluent limitations presented in Paragraphs A.1 through A.7 of this part are applicable during both the temporary and permanent Waste Water Treatment Facility discharge periods.

2. No later than 14 calendar days following a date identified in any schedule of compliance, the permittee shall submit to the Director, either a report of progress or, in the case of specific actions being required by identified dates, a written notice of compliance or noncompliance. In the latter case, the notice shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

C. MONITORING AND REPORTING

1. Reporting (January 1, 1982 to June 30, 1982):

   Monitoring results obtained during the previous month shall be summarized and reported on a Discharge Monitoring Report Form postmarked no later than the 28th day of the month following the completed reporting period. The first report is due on the 28th day of the month following the effective date.

2. Reporting (July 1, 1982 to expiration date):

   Monitoring results obtained during the previous 6 month(s) shall be summarized for each month and reported on separate Discharge Monitoring Report Form(s) postmarked no later than the 28th day of the month following the completed reporting period. The first report is due on December 28, 1982.

3. Report Copies:

   Duplicate signed copies of these, and all other reports required herein, shall be submitted to the Director and the State at the following addresses:

ENVIRONMENTAL PROTECTION AGENCY
Box 8127
Boston, MA 02114

The state agency is:

Massachusetts Division of Water Pollution Control
Western Regional Office
Draper Hall, University of Massachusetts
Amherst, MA 01002

Signed copies of all other notifications and reports required by this permit shall be submitted to the State at:

Massachusetts Division of Water Pollution Control
Permit Section - 7th Floor
1 Winter Street
Boston, Massachusetts 02108

D. STATE PERMIT CONDITIONS

This Discharge Permit is issued jointly by the U. S. Environmental Protection Agency and the Division of Water Pollution Control under Federal and State law, respectively. As such, all the terms and conditions of this permit are hereby incorporated into and constitute a discharge permit issued by the Director of the Massachusetts Division of Water Pollution Control pursuant to M.G.L. Chap. 21, §43.

Each Agency shall have the independent right to enforce the terms and conditions of this Permit. Any modification, suspension or revocation of this Permit shall be effective only with respect to the Agency taking such action, and shall not affect the validity or status of this Permit as issued by the other Agency, unless and until each Agency has concurred in writing with such modification, suspension or revocation. In the event any portion of this Permit is declared, invalid, illegal or otherwise issued in violation of State law such permit shall remain in full force and effect under Federal law as an NPDES Permit issued by the U. S. Environmental Protection Agency. In the event this Permit is declared invalid, illegal or otherwise issued in violation of Federal law, this Permit shall remain in full force and effect under State law as a Permit issued by the Commonwealth of Massachusetts.

PART II
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DEFINITIONS

GENERAL REQUIREMENTS

(a) Duty to comply. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Clean Water Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

(1) The permittee shall comply with effluent standards or prohibitions established under section 307(a) of the CWA for toxic pollutants within the time provided in the regulations that establish these standards or prohibitions, even if the permit has not yet been modified to incorporate the requirement.

(2) The CWA provides that any person who violates a permit condition implementing Sections 301, 302, 306, 307, 308, 318, or 405 of the CWA is subject to a civil penalty not to exceed $10,000 per day of such violation. Any person who willfully or negligently violates permit conditions implementing Sections 301, 302, 306, 307, or 308 of the Act is subject to a fine of not less than $2,500 nor more than $25,000 per day of violation, or by imprisonment for not more than 1 year, or both.

(b) Duty to reapply. If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must apply for and obtain a new permit. The permittee shall submit a new application at least 180 days before the expiration date of the existing permit, unless permission for a later date has been granted by the Director. (The Director shall not grant permission for applications to be submitted later than the expiration date of the existing permit.)

(c) Duty to halt or reduce activity. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. Upon reduction, loss, or failure of the treatment facility, the permittee shall, to the extent necessary to maintain compliance with its permit, control production or all discharges or both until the facility is restored or an alternative method of treatment is provided. This requirement applies, for example, when the primary source of power of the treatment facility fails or is reduced or lost.

(d) Duty to mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

(e) Proper operation and maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

(f) Permit actions. This permit may be modified, revoked and reissued, or terminated for cause, including but not limited to: (1) Violation of any terms or conditions of this permit; (2) Obtaining this permit by misrepresentation or failure to disclose all relevant facts; or (3) a change in any condition that requires either a temporary or permanent reduction or elimination of the authorized discharge. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

(g) Property rights. This permit does not convey any property rights of any sort, or any exclusive privilege.

(h) Duty to provide information. The permittee shall furnish to the Director, within a reasonable time, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit.

(i) Inspection and entry. The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(1) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

(2) Have access to and copy, at reasonable times, any records that must be kept under the conditions of

this permit;

(3) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

(4) Sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the CWA, any substances or parameters at any location.

(j) Monitoring and records.

(1) Samples and measurements taken for the purpose of monitoring shall be representative of the volume and nature of the discharged over the sampling and reporting period.

(2) The permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings from continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least 3 years from the date of the sample, measurement, report or application. This period may be extended by request of the Director at any time.

(3) Records of monitoring information shall include:

(i) The date, exact place, and time of sampling or measurements;

(ii) The individual(s) who performed the sampling or measurements;

(iii) The date(s) analyses were performed;

(iv) The individual(s) who performed the analyses;

(v) The analytical techniques or methods used; and

(vi) The results of such analyses.

(4) Monitoring must be conducted according to test procedures approved under 40 C.F.R. Part 136, unless other test procedures have been specified in this permit.

(5) The CWA provides that any person who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit shall upon conviction, be punished

by a fine of not more than $10,000 or by imprisonment for not more than 6 months or by both.

(6) Monitoring results must be reported on a Discharge Monitoring Report (DMR).

(7) If the permittee monitors any pollutant more frequently than required by the permit, using test procedures approved under 40 C.F.R. Part 136 or as specified in the permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

(k) Signatory requirement. All applications, reports, or information submitted to the Director shall be signed and certified in accordance with 40 C.F.R.§§122.6 and 122.7. The CWA provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance shall, upon conviction, be punished by a fine of not more than $10,000, or by imprisonment for not more than 6 months, or by both.

(l) Reporting requirements.

(1) Planned changes. The permittee shall give notice to the Director as soon as possible of any planned physical alterations or additions to the permitted facility.

(2) Anticipated noncompliance. The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(3) Transfers. This permit is not transferable to any person except after written notice to the Director. The Director may require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the CWA.

(4) Monitoring reports. Monitoring results shall be reported at the intervals specified elsewhere in this permit.

(5) Twenty-four hour reporting. The permittee shall report any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances or the next working day. A written submission shall also be provided within five (5) days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

The following information must be reported within 24 hours (24-hour reporting) or the next working day:

(i) Any unanticipated bypass which causes a violation of any effluent limitation in the permit; or

(ii) Any upset which causes a violation of any effluent limitation in the permit; or

(iii) Any violation of a maximum daily discharge limitation for any of the pollutants specifically listed by the Director in the permit.

The Director may waive the written report on a case-by-case basis if the oral report has been received within 24 hours or the next working day.

(6) Other noncompliance. The permittee shall report all instances of noncompliance not reported under paragraphs (1), (2), and (5), of this section, at the time monitoring reports are submitted. The reports shall contain the information required in paragraph (1)(5) of this section.

(7) Other information. Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Director, it shall promptly submit such facts or information.

(m) Bypass

(1) Definitions.

(i) "Bypass" means the intentional diversion of waste streams from any portion of a treatment facility.

(ii) "Severe property damage" means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

(2) Prohibition of bypass.

(i) Bypass is prohibited, and the Director may take enforcement action against a permittee for bypass, unless all the following conditions occur:

(A) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(B) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if the permittee could have installed adequate backup equipment to prevent a bypass which occured during normal periods of equipment downtime or preventive maintenance; and

(C) The permittee submitted notices as required under paragraph (m)(3) of this section.

(ii) The Director may approve an anticipated bypass, after considering its adverse effects, if the Director determines that it will meet the three conditions listed above in paragraph (m)(2)(i) of this section.

(iii) Bypass not exceeding limitations. The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of paragraph (m)(3) of this section.

(3) Notice

(i) Anticipated bypass. If the permittee knows in advance of the need for a bypass, it shall submit prior notice, if possible at least ten days before the date of the bypass.

(ii) Unanticipated bypass. The permittee shall submit notice of an unanticipated bypass as required in paragraph (l)(5) of this section (24-hour notice).

(n) Upset

(1) Definition. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

(2) Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with such technology-based permit effluent limitations if the requirements of paragraph (n)(3) of this section are met. No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

(3) Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:

(i) An upset occurred and that the permittee can identify the specific cause(s) of the upset;

(ii) The permitted facility was at the time being properly operated;

(iii) The permittee submitted notice of the upset as required in paragraph (l)(5) of this section (24-hour notice); and

(iv) The permittee complied with any remedial measures required under (d) above.

(4) Burden of proof. In any enforcement proceeding the permittee seeking to establish the occurrence of an upset has the burden of proof.

(o) Change in Discharge

All discharges authorized herein shall be consistent with the terms and conditions of this permit. The discharge of any pollutant identified in this permit more frequently than or at a level in excess of that authorized shall constitute a violation of the permit. Any anticipated facility expansions, production increases, or process modifications which will result in new, different, or increased discharges of pollutants must be reported by submission of a new NPDES application or, at least 180 days prior to commencement of such discharges if such changes will not violate the effluent limitations specified in this permit, by notice, in writing, to the Director of such changes. Following such notice, the permit may be modified to specify and limit any pollutants not previously limited.

Until such modification is effective, any new or increased discharge in excess of permit limits or not specifically authorized by the permit constitutes a violation.

(p) Removed Substances

Solids, sludges, filter backwash, or other pollutants removed in the course of treatment or control of wastewaters shall be disposed of in a manner consistent with applicable Federal and State laws and regulations including, but not limited to the CWA and the Federal Resource Conservation and Recovery Act, 42 U.S.C. §§6901 et seq., and regulations promulgated thereunder.

(q) Power Failures

In order to maintain compliance with the effluent limitations and prohibitions of this permit, the permittee shall either:

(1) In accordance with the Schedule of Compliance contained in Part I, provide an alternative power source sufficient to operate the wastewater control facilities;

or, if such alternative power source is not in existence, and no date for its implementation appears in Part I,

(2) Halt, reduce or otherwise control production and/or all discharges upon the reduction, loss, or failure of the primary source of power to the wastewater control facilities.

(r) Availability of Reports

Except for data determined to be confidential under Paragraph X below, all reports prepared in accordance with the terms of this permit shall be available for public inspection at the offices of the State water pollution control agency and the Regional Administrator. As required by the CWA, effluent data shall not be considered confidential. Knowingly making any false statement on any such report may result in the imposition of criminal penalties as provided for in Section 309 of the CWA.

(s) Oil and Hazardous Substance Liability

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee is or may be subject under Section 311 of the CWA.

(t) State Laws

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable State law or regulation under authority preserved by Section 510 of the CWA.

(u) Other Laws

The issuance of a permit does not authorize any injury to persons or property or invasion of other private rights, nor does it relieve the permittee of its obligation to comply with any other applicable Federal, State, and local laws and regulations.

(v) Severability

The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

(w) Reopener Clause

The Regional Administrator reserves the right to make appropriate revisions to this permit in order to establish any appropriate effluent limitations, schedules of compliance, or other provisions which may be authorized under the CWA in order to bring all discharges into compliance with the CWA.

(x) Confidentiality of Information.

(1) In accordance with 40 C.F.R. Part 2, any information submitted to EPA pursuant to these regulations may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission in the manner prescribed on the application form or instructions or, in the case of other submissions, by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may

make the information available to the public without further notice. If a claim is asserted, the information will be treated in accordance with the procedures in 40 C.F.R. Part 2 (Public Information).

(2) Claims of confidentiality for the following information will be denied:

(i) The name and address of any permit applicant or permittee;

(ii) Permit applications and permits; and

(iii) NPDES effluent data.

(3) Information required by NPDES application forms provided by the Director under 40 C.F.R. §§122.4 and 122.53 may not be claimed confidential. This includes information submitted on the forms themselves and any attachments used to supply information required by the forms.

(y) Right of Appeal.

Within thirty (30) days of receipt of notice of a final permit decision, the permittee may submit a request to the Regional Administrator for an evidentiary hearing under Subpart E, or a formal hearing under Subpart F, of 40 C.F.R. Part 124, to reconsider or contest that decision. The request for a hearing must conform to the requirements of 40 C.F.R. §124.74.

DEFINITIONS

1. For purposes of this permit, the following definitions shall apply.

Administrator means the Administrator of the United States Environmental Protection Agency, or an authorized representative.

Applicable standards and limitations means all State, interstate, and Federal standards and limitations to which a "discharge" or a related activity is subject to, including water quality standards, standards of performance, toxic effluent standards or prohibitions, "best management practices," and pretreatment standards under sections 301, 302, 303, 304, 306, 307, 308, 403, and 405 of CWA.

Application means the EPA standard national forms for applying for a permit, including any additions, revisions or modifications to the forms; or forms approved by EPA for use in "approved States," including any approved modifications or revisions.

Average - The arithmetic mean of values taken at the frequency required for each parameter over the specified period. For total and/or fecal coliforms, the average shall be the geometric mean.

Average monthly discharge limitation means the highest allowable average of "daily discharges" over a calendar month, calculated as the sum of all daily discharges measured during a calendar month divided by the number of daily discharges measured during that month.

Average weekly discharge limitation means the highest allowable average of "daily discharges" over a calendar week, calculated as the sum of all daily discharges measured during a calendar week divided by the number of daily discharges measured during that week.

Best management practices ("BMPs") means schedules of activities, prohibitions of practices, maintenance procedures, and other management practices to prevent or reduce the pollution of "waters of the United States." BMPs also include treatment requirements, operating procedures, and practices to control plant site runoff, spillage or leaks, sludge or waste disposal, or drainage from raw material storage.

Best Professional Judgement (BPJ) means a case-by-case determination of best practicable treatment (BPT), best available treatment (BAT) or other appropriate standard based on an evaluation of the available technology to achieve a particular pollutant reduction.

Composite Sample - A sample consisting of a minimum of eight grab samples collected at equal intervals during a 24-hour period (or lesser period as specified in the section on Monitoring and Reporting) and combined proportional to flow, or a sample continuously collected proportionally to flow over that same time period.

CWA means the Clean Water Act (formerly referred to as the Federal Water Pollution Control Act or Federal Water Pollution Control Act Amendments of 1972) Pub. L. 92-500, as amended by Pub. L. 95-217 and Pub. L. 95-576; 33 U.S.C. §§1251 et seq.

Daily Discharge means the discharge of a pollutant measured during a calendar day or any 24-hours period that reasonably represents the calendar day for purposes of sampling. For pollutants with limitations expressed in units of mass, the daily discharge is calculated as the total mass of the pollutant discharged over the day. For pollutants with limitations expressed in other units of measurements, the daily discharge is calculated as the average measurement of the pollutant over the day.

Director means Director, Enforcement Division, EPA, Region I.

Discharge of a pollutant means:

(a) Any addition of any "pollutant" or combination of pollutants to "waters of the United States" from any "point source," or

(b) Any addition of any pollutant or combination of pollutants to the waters of the "contiguous zone" or the ocean from any point source other than a vessel or other floating craft which is being used as a means of transportation.

This definition includes additions of pollutants into waters of the United States from: surface runoff which is collected or channelled by man; discharges through pipes, sewers, or other conveyances owned by a State, municipality, or other person which do not lead to a treatment works; and discharges through pipes, sewers, or other conveyances leading into privately owned treatment works.

This term does not include an addition of pollutants by any "indirect discharger" as defined in 40 C.F.R. §122.3

Discharge Monitoring Report Form ("DMR") means the EPA standard national form, including any subsequent additions, revisions, or modifications, for the reporting of self-monitoring results by permittees. DMRs must be used by "approved States" as well as by EPA. EPA will supply DMRs to any approved State upon request. The EPA national forms may be modified to substitute the State Agency name, address, logo, and other similar information, as appropriate, in place of EPA's.

Effluent limitation means any restriction imposed by the Director on quantities, discharge rates, and concentrations of "pollutants" which are "discharged" from "point sources" into "waters of the United States," the waters of the "contiguous zone," or the ocean.

Effluent limitations guidelines means a regulation published by the Administrator under Section 304(b) of CWA to adopt or revise "effluent limitations."

EPA means the United States "Environmental Protection Agency."

Grab Sample - An individual sample collected in a period of less than 15 minutes.

Hazardous Substance means any substance designated under 40 C.F.R. Part 116 pursuant to Section 311 of CWA.

Indirect Discharger means a non-domestic discharger introducing pollutants to a publicly owned treatment works.

Industrial User means a non-domestic discharger introducing pollutants to a publicly owned treatment works.

Maximum daily discharge limitation (NPDES) means the highest allowable "daily discharge."

Interference means an addition or disruption of the POTW, its treatment processes or operations, or its sludge processes, use or disposal which is cause of or significantly contributes to either a violation of any requirement of the POTW's NPDES permit (including an increase in the magnitude or duration of a violation) or to the prevention of sewage sludge use or disposal by the POTW in accordance with the following statutory provisions and regulations or permits issued thereunder (or more stringent State or local regulations): Section 405 of the Clean Water Act, the Solid Waste Disposal Act(SWDA) (including title II more commonly referred to as the Resource Conservation and Recovery Act(RCRA) and including State regulations contained in any State sludge management plan prepared pursuant to Subtitle D of the SWDA), the Clean Air Act, and the Toxic Substance Control Act. An Industrial User significantly contributes to such a permit violation or prevention of sludge use or disposal in accordance with above-cited authorities whenever such User:

(a) Discharges a daily pollutant loading in excess of that allowed by contract with the POTW or by Federal, State, or local law;
(b) Discharges wastewater which substantially differs in nature or constituents from the User's average Discharge; or
(c) Knows or has reason to know that its Discharge, alone or in conjunction with Discharges from other sources, would result in a POTW permit violation or prevent sewage sludge use or disposal in accordance with the above-cited authorities as they apply to the POTW's selected method of sludge management.

Municipality means a city, town, borough, county, parish, district, association, or other public body created by of under State law and having jurisdiction over disposal or sewage, industrial wastes, or other wastes, or an Indian tribe or an authorized Indian tribe organization, or a designated and approved management agency under section 208 of CWA.

National Pollutant Discharge Elimination System means the national program for issuing, modifying, revoking and reissuing, terminating, monitoring and enforcing permits, and imposing and enforcing pretreatment requirements, under sections 307, 402, 318, and 405 of CWA. The term includes an "approved program."

New discharger means any building, structure, facility, or installation:

(a)(1) From which there is or may be a new or additional "discharge of pollutants" at a "site" at which on October 18, 1972 it had never discharged pollutants;

(2) Which has never received a finally effective NPDES "permit" for discharges at that site; and

(3) Which is not a "new source."

(b) This definition includes an "indirect discharger" which commences discharging into "waters of the United States." It also includes any existing mobile point source, such as an offshore oil drilling rig, seafood processing rig, seafood processing vessel, or aggregate plant, that begins discharging at a location for which it does not have an existing permit.

New Source means any building, structure, facility, or installation from which there is or may be a "discharge of pollutants," the construction of which commenced:

(a) After promulgation of standards of performance under Section 306 of CWA which are applicable to such source; or

(b) After proposal of standards of performance in accordance with Section 306 of CWA which are applicable to such source, but only if the standards are promulgated in accordance with Section 306 within 120 days of their proposal.

NPDES means "National Pollutant Discharge Elimination System."

Owner or operator means the owner or operator of any "facility or activity" subject to regulation under the NPDES programs.

Pass Through means the Discharge of pollutants through the POTW into navigable waters in quantities or concentrations which are a cause of or significantly contribute to a violation of any requirement of the POTW's NPDES permit (including an increase in the magnitude or duration of a violation). An industrial User significantly contributes to such permit violation where it:

(a) Discharges a daily pollutant loading in excess of that allowed by contract with the POTW or by Federal, State, or local law:

(b) Discharges wastewater which substantially differs in nature and constituents from the User's average Discharge:

(c) Knows or has reason to know that its Discharge alone or in conjunction with Discharges from other sources would result in a permit violation; or

(4) Knows or has reason to know that the POTW is, for any reason, violating its final effluent limitations in its permit and that such Industrial User's Discharge either alone or in conjuction with Discharges from other sources, increases the magnitude or duration of the POTW's violations.

Permit means an authorization, license, or equivalent control document issued by EPA or an "approved State."

Point source means any discernible, confined, and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, vessel, or other floating craft, from which pollutants are or may be discharged. This term does not include return flows from irrigated agriculture.

Pollutant means dredged spoil, solid waste, incinerator residue, filter backwash, sewage, garbage, sewage sludge, munitions, chemical wastes, biological materials, radioactive materials (except those regulated under the Atomic Energy Act of 1954, as amended (42 U.S.C. §§2011 et seq.)), heat, wrecked or discarded equipment, rock, sand, cellar dirt and industrial, municipal, and agricultural waste discharged into water. It does not mean:

(a) Sewage from vessels; or

(b) Water, gas, or other material which is injected into a well to facilitate production of oil or gas, or water derived in association with oil and gas production and disposed of in a well, if the well used either to facilitate production or for disposal purposes is approved by authority of the State in which the well is located, and if the State determines that the injection or disposal will not result in the degradation of ground or surfact water resources.

Primary industry category means any industry category listed in the NRDC settlement agreement (Natural Resources Defense Council et al. v. Train, 8 E.R.C. 2120 (D.D.C. 1976), modified 12 E.R.C. 1833 (D.D.C. 1979)); also listed in Appendix A of 40 C.F.R. Part 122.

Process wastewater means any water which, during manufacturing or processing, comes into direct contact with or results from the production or use of any raw material, intermediate product, finished product, byproduct,or waste product.

Publicly owned treatment works ("POTW") means any facility or system used in the treatment (including recycling and reclamation) of municipal sewage or industrial wastes of a liquid nature which is owned by a "State" or "municipality." This definition includes sewers, pipes, or other conveyances only if they convey wastewater to a POTW providing treatment.

Regional Administrator means the Regional Administrator, EPA, Region I, Boston, Massachusetts.

State means any of the 50 States, the District of Columbia, Guam, the Commonwealth of Puerto Rico, the Virgin Islands, American Samoa, the Trust Territory of the Pacific Islands

Secondary Industry Category means any industry category which is not a "primary industry category."

Sewage Sludge means the solids, residues, and precipitate separated from or created in sewage by the unit processes of a "publicly owned treatment works." "Sewage" as used in this definition means any wastes, including wastes from humans, households, commercial establishments, industries, and storm water runoff, that are discharged to or otherwise enter a publicly owned treatment works.

Toxic Pollutant means any pollutant listed as toxic in Appendix D of 40 C.F.R. Part 122, under Section 307(a)(1) of CWA.

Waters of the United States means:

(a) All waters which are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters which are subject to the ebb and flow of the tide;

(b) All interstate waters, including interstate "wetlands."

(c) All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, "wetlands," sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds the use, degradation, or destruction of which would affect or could affect interstate or foreign commerce including any such waters:

   (1) Which are or could be used by interstate or foreign travelers for recreational or other purposes;

   (2) From which fish or shellfish are or could be taken and sold in interstate or foreign commerce; or

(3) Which are used or could be used for industrial purposes by industries in interstate commerce;

(d) All impoundments of waters otherwise defined as waters of the United States under this definition;

(e) Tributaries of waters identified in paragraphs (a) - (d) of this definition;

(f) The territorial sea; and

(g) "Wetlands" adjacent to waters (other than waters that are themselves wetlands) identified in paragraphs (a) - (f) of this definition.

Wetlands means those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas.

2. The following abbreviations, when used, are defined below.

cu. M/day or M^3/day	cubic meters per day
mg/l	milligrams per liter
ug/l	micrograms per liter
lbs/day	pounds per day
kg/day	kilograms per day
Temp. °C	temperature in degrees Centigrade
Temp. °F	temperature in degrees Fahrenheit
Turb.	turbidity measured by the Nephelometric Method (NTU)
TNFR or TSS	total nonfilterable residue or total suspended solids
DO	dissolved oxygen
BOD	five-day biochemical oxygen demand unless otherwise specified
TKN	total Kjeldahl nitrogen as nitrogen

Total N	total nitrogen
NH_3-N	ammonia nitrogen as nitrogen
Total P	total phosphorus
COD	chemical oxygen demand
TOC	total organic carbon
Surfactant	surface-active agent
pH	a measure of the hydrogen ion concentration
PCB	polychlorinated biphenyl
CFS	cubic feet per second
MGD	million gallons per day
Oil & Grease	Freon extractable material
Total Coliform	total coliform bacteria
Fecal Coliform	total fecal coliform bacteria
ml/l	milliliter(s) per liter
NO_3-N	nitrate nitrogen as nitrogen
NO_2-N	nitrite nitrogen as nitrogen
NO_3-NO_2	combined nitrate and nitrite nitrogen as nitrogen
Cl_2	total residual chlorine

ATTACHMENT A

MEMORANDUM OF UNDERSTANDING, dated this sixth day of March, 1980, between The Commonwealth of Massachusetts (the "Commonwealth"), as represented by the Governor of the Commonwealth and the Commissioner of the Massachusetts Department of Environmental Quality Engineering (the "DEQE"), and Holyoke Water Power Company (the "Company"), concerning certain agreements with respect to the burning of coal at the Mt. Tom Power Plant (the "power plant").

WHEREAS, the Commonwealth and the Company (hereafter collectively "the parties") share mutual concern that the New England region depends to a significant degree on imported residual oil for electric power generation and believe that the permanent substitution of coal for oil at the power plant ("the conversion") would be a practical and desirable way to reduce this dependence if the conversion can be implemented in an economically feasible and environmentally acceptable fashion;

WHEREAS, the parties recognize that the conversion would result in savings to consumers; and

WHEREAS, the parties acknowledge that the Company does not and will not have the financial capability to undertake the conversion and will be able to implement the conversion only if it is assured of an ability to recover the full cost of conversion and all subsequent costs incurred as a result of the conversion by means of oil conservation adjustments or charges of the type described below;

NOW THEREFORE, in consideration of the foregoing and of the mutual covenants and agreements contained herein, the parties hereby agree as follows:

I. General Undertakings

Subject in all respects to the conditions set forth in Part II of this Memorandum, the Company will convert the power plant to coal in accordance with the terms hereof, and the Commonwealth will use its best efforts to assist the Company in the financing and implementation of the conversion. In implementing the conversion, the parties will take whatever measures are practical and environmentally acceptable to minimize the cost of converting the power plant and to obtain prompt recovery of that cost from customers benefitting from the conversion. The parties will also take such measures as may be necessary to comply with applicable Federal and State environmental laws and regulations in force as of the date of this Memorandum and as amended or modified in accordance with the provisions of Part V hereof. In the event any of such environmental laws or regulations is amended or modified other than in accordance with the provisions of Part V hereof, the Company reserves the right at its option: (i) to terminate its obligations under this Memorandum by electing not to proceed further with the conversion, (ii) to proceed with the conversion and recover additional environmental compliance costs as provided in the fourth paragraph of this Part I, or (iii) to remove the power plant either temporarily or permanently from service.

The parties anticipate that the conversion, including the installation of all pollution control and waste treatment and disposal equipment necessary to enable the power plant to comply with applicable Federal and State laws and regulations, will be initiated immediately following the satisfaction of all conditions set forth in Part II hereof and will be implemented during a period of approximately 42 months thereafter (the "conversion period"). It is further anticipated that the power plant will begin burning coal approximately 12 months following the start of the conversion period.

The Company estimates that depending upon the environmental requirements to be met the potential cost of conversion could be as much as $35 million, exclusive of the Company's cost of capital during the period extending from the time conversion costs are first incurred until the time they are fully recovered from ratepayers. The parties contemplate that the Company will recover all conversion costs, net of taxes and including the Company's cost of capital referred to above, by means of oil conservation adjustments. Such adjustments will commence at the time the power plant first begins to burn coal, and will be designed to recover all conversion costs from retail, wholesale and special contract customers of the Company and its affiliates in Massachusetts and Connecticut by a charge equal to two-thirds of the fuel-cost savings resulting from the differential in coal and oil prices in effect at the time the power plant first begins to burn coal, but such charge shall not be less than that necessary to pay the maximum potential estimated costs of conversion within 36 months. The parties agree to use their best efforts to obtain all Federal and State regulatory approvals and all State legislative action necessary to permit the Company to implement such adjustments. In the event that the Company becomes entitled, by reason of the conversion, to any Federal or State grant, such grant either will be applied to reduce the amount of conversion costs which the Company would otherwise recover by means of such oil conservation adjustments or, if such grant is received by the Company after the termination of such adjustments, will be refunded to customers.

Should the Company be required at any time during the conversion period or the period the oil conservation adjustments are in effect to take any pollution control (including noise abatement) or waste treatment or disposal measures not contemplated by this Memorandum, the cost of such measures will be recovered from the Company's customers by means of the oil conservation adjustments described above. Should the Company be required to take any such measures at any time following the conversion period or termination of the oil conservation adjustments, whichever is later, the parties agree that since such measures would result from the conversion contemplated by this Memorandum, the cost of such measures should be recovered by means of future adjustments similar to such oil conservation adjustments. In such case, the parties agree to use their best efforts to obtain all additional Federal and State regulatory approvals and all additional State legislative action necessary to permit the Company to again implement such similar adjustments.

The parties agree that no construction, reconstruction or modification will be initiated at the power plant until (1) such time as information required under Section 7.02(2) of Massachusetts' Regulations for the Control of Air Pollution in the Pioneer Valley Air Pollution Control District shall have been made available to the DEQE for its review pursuant to that Section, and (2) the DEQE shall have taken all action necessary to approve the construction, reconstruction or modification being proposed.

Insofar as air quality regulations are concerned, the parties agree that the appropriate mechanism for encouraging the conversion of the power plant to coal in an economic and environmentally acceptable fashion is (1) for the Company to request the U.S. Environmental Protection Agency ("EPA") to issue a Delayed Compliance Order ("DCO") expiring approximately 42 months after it is issued and approving the interim particulate emission limitation set out in this Memorandum, and (2) to promulgate a State regulation that will specify (a) the sulfur in fuel limitation set out herein that the parties intend will be applicable to the facility throughout the term of this Memorandum and (b) the post-conversion particulate emission limitation, also set out herein, that the parties intend will become applicable to the facility when the DCO has expired. The parties agree to use their best efforts to obtain the above-described DCO from EPA and to obtain EPA's approval of the particulate emission and sulfur in fuel limitations set out herein. The parties further agree to use their best efforts, consistent with applicable Federal laws and regulations, applicable State laws and the responsibility of the Commonwealth and the DEQE to protect the environment and the public health and welfare, to insure that the sulfur in fuel and post-conversion particulate emission limitations set out in this Memorandum will remain in force throughout the term hereof.

II. Conditions

The Company will not be required to initiate the conversion, or to take any steps required to prepare for the conversion, unless and until all of the following conditions have been fulfilled to the Company's satisfaction:

1. The Company shall have received all Federal and State regulatory and/or legislative approvals, and the Company shall have effected and obtained all necessary Federal and State approvals of any amendments or supplements to its power supply contracts, necessary to permit the Company to implement the oil conservation adjustments described above and to otherwise exercise its rights and meet its obligations under this Memorandum;

2. EPA shall have issued the DCO referred to above approving the interim particulate emission limitations set out in this Memorandum; and

3. The DEQE shall have promulgated, and EPA shall have approved, regulations specifying (1) the sulfur in fuel limitation and (2) the post-conversion particulate emission limitation also set out in this Memorandum.

III. Legal Rights.

This Memorandum states the agreements and assumptions arrived at by the parties after many discussions and is intended to serve as a measure of their intention to act in accordance with the understandings stipulated herein. However, notwithstanding any other language in this or any other section of this Memorandum, nothing herein indicates, or should be construed to indicate, any intention on the part of the Company, the Commonwealth or the DEQE to void or waive any legal rights or regulatory responsibilities pursuant to their authority and respective positions, including but not limited to the responsibility of the Commonwealth and the DEQE to protect the environment and the public health and welfare and the responsibility of the Company to meet the energy needs of its customers in an adequate, reliable and economic manner, consistent with its financial condition and ability to do so.

The parties agree to use their best efforts to obtain from appropriate State and Federal authorities any and all licenses, permits, approvals, waivers, exemptions and/or legislative action necessary to permit the parties to perform and adhere to the agreements and understandings set forth herein. The Commonwealth and the DEQE agree that as long as the agreements and understandings set forth herein shall remain in force, they will not (1) propose any law, regulation or guideline which may apply to or affect the power plant without first consulting with the Company concerning such proposal, or (2) propose or advocate any law, or propose or adopt any regulation or guideline not required under applicable State laws or under applicable Federal statutes and regulations, which will supersede, impair, limit or otherwise affect any of such agreeements or understandings in any way adverse to the rights and interests of the Company hereunder.

IV. Term

The agreements and understandings set forth in this Memorandum shall remain in full force and effect until such time as the power plant in its present configuration (i.e., utilizing the boiler and turbine presently in place, regardless of the type of fuel being burned to generate electricity) is permanently retired from service.

V. Environmental Standards And Methods Of Waste Treatment And Disposal.

A. Air Quality

1. Particulate Control

The parties agree that as long as the DCO remains in effect, particulate emissions from the power plant will not exceed 0.48 pounds per million Btu heat input while burning coal with a sulfur content of 1.21 pounds per million Btu heat input.

The parties further agree that control equipment will be installed during the conversion period that will enable the power plant to achieve a particulate emission rate, following the expiration of the DCO, of 0.08 pounds per million Btu when burning a coal with an average sulfur content of 1.21 pounds per million Btu heat input.

An initial emissions test, performed in accordance with EPA Method 5 (Revision dated 7/1/78), will be conducted by the Company within 60 days of achievement by the power plant of its maximum coal-fired power rating.

2. Sulfur

The parties agree that throughout the term of this Memorandum, to the extent permitted by applicable State laws and applicable Federal laws and regulations, (1) the sulfur in fuel limit for the facility will be 1.21 pounds of sulfur per million Btu heat input with compliance based on a running 30-day average of sulfur in fuel as determined from 24-hour "as burned" analyses compiled by the Company, and (2) during any one 24-hour period the sulfur in fuel utilized by the power plant operating on coal shall not exceed 1.60 pounds per million Btu. The Company will provide the DEQE with monthly reports of the 24-hour "as burned" analyses and the monthly average of sulfur in fuel for the reporting period.

B. Ash Disposal

The Company agrees that at all times during which the power plant is burning coal, it will have available unused on-site storage capacity for ash produced during at least one year's operation of the power plant or will have in effect suitable commercial arrangements for ash disposal. In the event offsite disposal arrangements become necessary or desirable, the Commonwealth will use its best efforts to assist the Company in the acquisition and licensing of disposal sites.

C. Noise

In a good faith effort to minimize noise generated by the operation of the power plant, which consists principally of noise generated by coal-unloading activities, the Company agrees to make the following improvements in the plant's coal-unloading area: (1) to further enclose the plant's car shaker; (2) to line, as far as practicable, the plant's shaker and crusher facilities with noise and vibration absorbing materials; and (3) to substantially improve the plant's car-thawing facility. In addition, the Company will normally limit coal-unloading periods to 0730-2200 hours, Monday through Saturday, and 1000-2200 hours on Sundays.

The parties acknowledge that the improvements listed above are the only practicable and economically feasible steps which the Company can take to reduce noise resulting from the power plant's operation, and they agree that the reduced noise levels which are anticipated to result from these improvements will be acceptable to the Commonwealth. The parties further agree, however, that if the DEQE should receive repeated and justifiable complaints concerning noise generated by sources or activities at the power plant which have not been identified and are not anticipated as of the date of this Memorandum, the parties will discuss additional steps to reduce noise at the plant, and the Company will implement any noise-reduction measures which the parties agree are necessary and appropriate. In no event, however, will the Commonwealth or the DEQE seek to enforce the DEQE's sound-level-increase guideline (limiting increases in sound levels to not more than 10 decibels above ambient) at the property line of the power plant.

D. Water Quality

Normal plant wastewaters, maintenance washes, bottom ash and fly ash will be collected and treated with only occasional discharges resulting. All such discharges will be in compliance with applicable State and Federal requirements. To the extent such materials are available and suitable, dike walls surrounding wastewater, coal and ash storage areas will be constructed of materials already on site.

It is not anticipated that the Company will be required to line the wastewater storage ponds or the coal pile area at the power plant, since no significant impact on ground water is expected to result from coal, ash and wastewater storage at the plant. However, the Company will perform hydro-geologic studies to measure the effect of such storage on groundwater supplies and the waters of the Connecticut River, and to determine whether lining of coal and wastewater storage areas d/or other water treatment measures will be necessary. These studies will be conducted during a period of approximately two years beginning on the date of this Memorandum and will involve the collection of data during approximately one year's operation of the power plant on oil and approximately one year's operation on coal. Levels of water quality found to exist during the period when the power plant continues to burn oil will be used as a baseline for purposes of comparison with water quality levels found to exist following the conversion.

At the end of the test period, the parties will work together in analyzing the data collected and determining what effect, if any, the Company's on-site storage of coal and wastewaters has had on ground water supplies and the waters of the Connecticut River. If the parties determine that such storage has had a significant impact and that additional treatment is required, the Company will take such treatment measures as the DEQE, after consultation in good faith with the Company, may reasonably determine to be necessary and appropriate.

The parties further agree that if at any time during the term of this Memorandum, new evidence is developed which indicates that wastewater and coal storage at the power plant may threaten public health or cause environmental damage in ways which are not currently anticipated, the Company will take such additional treatment measures as the DEQE, after consultation in good faith with the Company, may reasonably determine to be necessary and appropriate to address such newly identified problems.

THE COMMONWEALTH OF MASSACHUSETTS

By Edward J. King
The Honorable Edward J. King
Governor

By Anthony D. Cortese
Anthony D. Cortese, Sc. D.
Commissioner, Massachusetts
Department of Environmental
Quality Engineering

HOLYOKE WATER POWER COMPANY

By Lelan F. Sillin, Jr.
Lelan F. Sillin, Jr.
Chairman and Chief Executive
Officer

DELAYED COMPLIANCE ORDER

awareness of measures which would prevent the standards from being exceeded. Ohio regulation OAC-3745-35, submitted to USEPA on February 25, 1980, contains procedures for involving the public in regulatory and other procedures to improve air quality.

Based on these submittals, USEPA approves Ohio's public notification procedures.

Section 128—State Boards

Section 128 of the Act requires that any boards which approve permits or enforcement orders under the Act must contain a majority of members who represent the public interest and do not derive any significant portion of their income from persons subject to permit or enforcement orders under the Act. It also requires that members of any such board adequately disclose any potential conflicts of interest. On July 27, 1979, Ohio submitted proposed amendments to the Ohio Revised Code, Section 3704, and on January 30, 1981, Ohio submitted an amended ORC 3704.

Chapter 102 of ORC 3704, contains provisions which require each member of a State board to file a statement which details possible conflicts of interest. The provisions of this chapter are consistent with the requirements of Section 128 of the Clean Air Act and ensure that a majority of the members of State boards will represent the public interest. Based on this submittal, USEPA approves Ohio's procedures for State boards.

Since USEPA views this action as a noncontroversial rulemaking, it is today approving the Ohio State Implementation Plan provisions which satisfy several general requirements of the Clean Air Act amending the following: Section 121—Consultation, Section 110(a)(2)(K)—Permit Fees, Section 126—Interstate Pollution, Section 127—Public Notification, and Section 128—State Boards. This action will be effective 60 days from the date of the Federal Register notice. However, if USEPA is notified within 30 days that someone wishes to submit comments, this action will be withdrawn and a new rulemaking will propose the action and establish a comment period.

Pursuant to the provisions of 5 U.S.C. Section 605(b), I hereby certify that the present rule will not have a significant economic impact on a substantial number of small entities since it imposes no burden on sources. This action only approves State actions. It imposes no new requirements.

Under Executive Order 12291 (46 FR 13193), USEPA must also judge whether a regulation is "major" and, therefore subject to the requirements of a Regulatory Impact Analysis. Today's action does not constitute a major regulation, as defined by Executive Order 12291, because this action only approves a State action. This regulation was submitted to the Office of Management and Budget (OMB) for review as required by Executive Order 12291.

Under section 307(b)(1) of the Clean Air Act, judicial review of this final action is available only by the filing of a petition for review in the United States Court of Appeals for the appropriate circuit within 60 days from date of this publication. Under section 307(b) the subject of today's notice may not be challenged later in civil or criminal proceedings brought by USEPA to enforce these requirements.

Note.—Incorporation by reference of the State Implementation Plan for the State of Ohio was approved by the Director of the Federal Register on July 1, 1981.

(Secs. 110, 121, 126, 127, 128, Clean Air Act, as amended (42 U.S.C. 7410(a), 7421, 7426, 7427, 7428))

Dated: November 18, 1981.

Anne M. Gorsuch,
Administrator.

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

Title 40 of the Code of Federal Regulations, Chapter I, Part 52 is amended as follows:

Subpart KK—Ohio

Section 52.1870(c) is amended by adding (subparagraph 32) as follows:

§ 52.1870 Identification of plan.

* * * * *

(c) * * *

(32) On July 27, 1979, the State of Ohio submitted materials to satisfy the general requirements of the Clean Air Act under Sections 110(a)(2)(K); 126, 127, and 128. On January 30, 1981, the State of Ohio also submitted an amended substitute Senate Bill 258, which was enacted into law on December 19, 1980, amending Ohio Revised Code 3704.

[FR Doc. 81-33914 Filed 11-23-81; 8:45 am]

BILLING CODE 6560-38-M

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40 CFR Part 55

[A-1-FRL 1975-4]

State and Federal Administrative Enforcement of Implementation Plan Requirements After Statutory Deadlines; Delayed Compliance Order for Holyoke Water Power Company's Mt. Tom Generating Station

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) announces the issuance of an administrative order called a Delayed Compliance Order (DCO) to Holyoke Water Power Company (HWPC), allowing the single boiler of its Mt. Tom Generating Station, located in Holyoke, Massachusetts to be converted from burning oil to burning coal. The increased particulate emissions caused by coal burning will mean that HWPC will be unable to comply with the Massachusetts State Implementation Plan (SIP) until February 15, 1984. Between now and February 15, 1984, HWPC will be allowed to burn coal despite this noncompliance. During this interim period, however, HWPC must install the pollution control equipment necessary to achieve final compliance with the Massachusetts SIP. This DCO sets forth a compliance schedule, emissions limitations, and other requirements of section 113(d)(5) of the Clean Air Act.

EFFECTIVE DATE: November 24, 1981.

ADDRESSES: Copies of all comments received, EPA's responses to these comments, and all reports required under the DCO are available for public inspection during normal business hours at the Environmental Protection Agency, Region I, JFK Federal Building, Room 1903, Boston, Massachusetts; and at the Pioneer Valley Air Pollution Control District, 3rd floor, 1414 State Street, Springfield, Massachusetts.

FOR FURTHER INFORMATION CONTACT: Arnold Leriche at the U.S. Environmental Protection Agency, Region I, JFK Federal Building, Room 1903, Boston, Massachusetts 02203 or telephone (617) 223-4448.

SUPPLEMENTARY INFORMATION: On May 21, 1981, HWPC, a subsidiary of Northeast Utilities, requested a DCO under Section 113(d)(5) of the Clean Air Act, 42 U.S.C. 7413(d)(5), to enable it to burn coal in the single 145 megawatt generating unit of its Mt. Tom

Generating Station in Holyoke, Massachusetts. HWPC proposed an immediate conversion from oil to coal burning and stated that this would cause temporary noncompliance at Mt. Tom with the following regulations contained in the EPA approved Massachusetts SIP:

310 CMR 7.02(8)—limiting particulate emissions to 0.12 pounds per million Btu heat input;

310 CMR 7.05(4)—limiting the ash content of fossil fuels to 9% dry weight (interpreted by the State as measured on a cargo received basis) and;

310 CMR 7.06(1)—limiting visible emissions to 20% opacity, expect up to 40% for no more than 6 minutes in any hours.

On July 31, 1981, EPA proposed (46 FR 39168) to issue a DCO to HWPC, exempting the Mt. Tom plant until February, 1984, from the above particulate emission and visible emission regulations, but not from the ash content regulation. EPA's proposal also contained interim pollution control requirements and emission limitations, as well as emissions and ambient monitoring and reporting requirements. These requirements, as well as EPA's findings on Mt. Tom's eligibility for a DCO, are explained in detail in EPA's proposed rulemaking notice and will not be repeated here.

The comment period on EPA's proposal ran from July 31 to September 4, 1981. A public hearing was held in Holyoke, Massachusetts on August 25, 1981. Ten persons testified at the public hearing, and four persons submitted written comments during the comment period. Of these fourteen commenters, four opposed the proposed DCO, three favored the proposed DCO, and seven favored the DCO but also expressed environmental concerns. As previously stated, EPA's responses to all the comments submitted are contained in several memoranda which are available for public inspection. Only those comments which have resulted in the two principal changes from EPA's proposal will be discussed in today's notice.

1. Ash Limitation—HWPC originally requested an exemption from the state ash regulation for the duration of the DCO period. EPA's proposal did not exempt Mt. Tom from meeting the state ash regulation because, in EPA's judgement, HWPC failed to show in its DCO application that it could not obtain coal that met the 9% ash (dry basis) limitation. At the public hearing, the Massachusetts Department of Environmental Quality Engineering suggested a 10% ash limitation. A second commenter testified that the only basis for an EPA waiver of the existing state ash regulation would be written documentation from HWPC of lack of supply of conforming coal. HWPC requested a 10% ash (as received) limitation, but did not provide any supporting documentation for its request. A 10% ash (as received) coal equates to approximately a 10½%–11% ash (dry basis) coal due to the difference in moisture contents. Subsequent to the hearing, one commenter wrote a letter supporting the 9% ash limitation. Also, HWPC submitted written documentation in support of its request for a 10% (as received) ash limit. Included in HWPC's support was a summary of contacts with fuel suppliers. HWPC sent requests for proposal to 120 suppliers asking for coal to meet a 10% ash (as received) specification. HWPC received responses from 25 suppliers, only 6 of which would guarantee to meet the 10% ash (as received) limit as well as other important specifications.

After publication of EPA's proposed DCO, which did not grant an exemption from the state's 9% ash (dry basis) regulation, HWPC recontacted the 6 suppliers to determine if any would guarantee delivery of 9% ash (dry basis) coal in addition to meeting all other necessary specifications. It should be noted that HWPC was unwilling to sign a 2 year contract with any supplier because it had not tested the coal in its Mt. Tom boiler. Furthermore, HWPC could not guarantee regular receipt of coal shipments during the winter of 1981–1982 because the thawing device for its coal unloading equipment is in disrepair. Primarily for these reasons, no supplier would guarantee 9% ash (dry basis) coal. Although EPA believes that HWPC's delayed contact with suppliers for the 9% ash (dry basis) coal resulted in predictable failure to secure a supply, EPA is convinced that a supply of 9% ash (dry basis) coal is unavailable to HWPC for the 1981–1982 winter season. However, HWPC can continue to contact suppliers about a 2 year contract for 9% ash (dry basis) coal to commence after the 1981–1982 winter. By that time, the weather will be warm enough to unload coal without the thawing devices, enough time will be available to install new thawing devices before the next winter, and enough time will have lapsed to allow HWPC to test potential conforming coal supplies in the Mt. Tom boiler.

Therefore, EPA is today permitting noncompliance with Massachusetts regulation 310 CMR 7.05(4) limiting ash content of coal to 9% (dry basis) for a period of 6 months from the date of initial coal burning at Mt. Tom. During this 6 month period, a 10% (as received) ash limitation will apply. In addition, HWPC must report on a monthly basis the results of its efforts to obtain conforming coal. HWPC may not stockpile nonconforming coal for use after the end of the 6 month period. During the 6 month period, EPA will review the results of HWPC's efforts to secure conforming coal. If EPA determines a further exemption is warranted, EPA will amend this DCO under its rulemaking procedures.

2. Ambient Monitoring—EPA's proposal required sulfur dioxide (SO_2) and/or total suspended particulate (TSP) ambient monitors at eight locations around the Mt. Tom plant. These eight locations were chosen based on consideration of high population exposure, as well as high plant impacts predicted by dispersion modeling.

Eight persons commented on EPA's ambient monitoring proposal. One commenter supported EPA's proposal, five commenters recommended an expanded monitoring network, one commenter recommended an expanded network that balanced other environmental concerns, and one commenter recommended a smaller monitoring network.

After reviewing the comments, EPA performed detailed site inspections of the eight proposed monitoring locations. As a result of these inspections, EPA is now requiring the following three changes:

(a) Mt. Tom ski area, Holyoke (called Smith's Ferry Site in EPA's proposal)—EPA's proposal required both SO_2 and TSP monitors. EPA is now requiring only SO_2 monitoring because the inspection revealed the site is near a gravel parking lot which would unduly influence future TSP measurements.

(b) Northampton area—EPA's proposal required both SO_2 and TSP monitors. EPA is now requiring only a TSP monitor. For purposes of data comparison, EPA prefers to retain the existing TSP monitor in Northampton. However, it is difficult to locate an SO_2 monitor at this site. Furthermore, no violations of SO_2 standards were predicted at this population-oriented site.

(c) Mt. Holyoke Range (proposed new site)—EPA's proposal required both SO_2 and TSP monitors. EPA is now requiring only an SO_2 monitor. This site is located in a state park; EPA is convinced that additional land clearing and noise associated with the siting and operation of a TSP monitor will have a significantly greater adverse impact on Mt. Holyoke than requiring an SO_2 monitor alone. Furthermore, EPA is confident that TSP levels can be adequately estimated from the SO_2 data to insure compliance with the primary TSP standards.

Following the close of the public comment period, EPA received objections from a citizen's advisory group concerning siting of the monitors at the Summit House and Mt. Holyoke Range locations, both of which are in a state park. The group, which advises the state on management of the park, was mainly concerned about the aesthetic impact of a new monitor and powerline in a forested area near a hiking trail. EPA is presently working with concerned citizens, HWPC, and the State to reach agreement on the location and number of monitors to be placed on these two sites in the state park, and on various means to minimize the adverse impacts of these monitors. Except for the elimination of the TSP monitor at the Mt. Holyoke Range site, EPA is not by today's Order reversing its proposed requirements to monitor at both park locations. However, the DCO allows EPA the flexibility to change the location and number of ambient monitors to reflect the results of continuing discussions with the above parties.

Therefore, after considering all comments received, the DCO request by the Holyoke Water Power Company, EPA's findings, and the written concurrence from the Governor of the Commonwealth of Massachusetts, this order is hereby issued. In addition, this Order is being made effective immediately.

(42 U.S.C. 7413(d))

Dated: November 17, 1981.

Anne M. Gorsuch,

Administrator, Environmental Protection Agency.

Before the United States Environmental Protection Agency Region I, John F. Kennedy Federal Building, Boston, MA 02203

Statutory Authority

This Order is issued under Sections 113(d)(5) and 114 of the Clean Air Act (the Act), as amended, 42 U.S.C. 7413(d)(5) and 7414. This Order contains a compliance schedule, interim requirements, monitoring and reporting requirements and other requirements which satisfy the terms of these Sections of the Act. Public notice has been provided under Section 113(d)(1) of the Act, 42 U.S.C. 7413(d)(1), and a copy of this Order has been provided to the Governor of the Commonwealth of Massachusetts to seek his concurrence.

In consideration of the foregoing, 40 CFR Part 55 is amended as follows:

PART 55—ENERGY RELATED AUTHORITY

1. By adding § 55.471 to read as follows:

Subpart W—Massachusetts

§ 55.471 Federal administrative orders issued under Section 113(d)(5) of the Act.

Findings

The Administrator of EPA (Administrator) makes the following findings:

(1) The Holyoke Water Power Company (HWPC) owns and operates the Mt. Tom Generating Station (Mt. Tom) located in Holyoke, Massachusetts.

(2) Mt. Tom is a major stationary source, having the potential to emit more than 100 tons per year of particulate and sulfur dioxide while using pollution control equipment.

(3) Currently, the single unit at Mt. Tom Burns residual oil.

(4) On June 30, 1977, the Federal Energy Administration issued a prohibition order under the Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.* (1974), which prohibited Mt. Tom from burning oil. Currently, the U.S. Department of Energy (DOE) is preparing an Environmental Impact Statement (EIS) which is required prior to issuance of a Notice of Effectiveness of the prohibition order.

(5) An implementation plan to regulate air pollution in Massachusetts has been approved by the Administrator of EPA under Section 110 of the Act, 42 U.S.C. 7410.

(6) 310 CMR 7.02(8) is part of the applicable State Implementation Plan (SIP) within the meaning of Section 113(d)(5) of the Act, 42 U.S.C. 7413(d)(5), and reads in pertinent part as follows:

No person owning, leasing, or controlling the operation of any fossil fuel utilization facility shall cause, suffer, allow, or permit emissions therefrom in excess of those emission limitations set forth in the following tables (0.12 lbs. of particulate per million Btu heat input).

(7) 310 CMR 7.05(4) is part of the applicable SIP within the meaning of Section 113(d)(5) of the Act, 42 U.S.C. 7413(d)(5), and reads in pertinent part as follows:

No person shall cause, suffer, allow, or permit the burning in the district (Pioneer Valley Air Pollution Control) of any fossil fuel containing an ash content in excess of nine percent (9%) by dry weight.

(8) 310 CMR 7.06(1) is part of the applicable SIP within the meaning of Section 113(d)(5) of the Act, 42 U.S.C. 7413(d)(5), and reads in pertinent part as follows:

(1) From Stationary Sources Other than Incinerators

(a) No person shall cause, suffer, allow, or permit the emission of smoke which has a shade, density, or appearance equal to or greater than No. 1 of the Chart (20%) for a period, or aggregate period of time in excess of six minutes during any one hour, provided that at no time during the said six minutes shall the shade, density, or appearance be equal to or greater than No. 2 of the Chart. (40%).

(9) EPA has determined that Mt. Tom will be unable to meet the requirements of 310 CMR 7.02(8), 7.05(4) and 7.06(1) if the unit converts to coal burning.

(10) Mt. Tom is located in the Hartford-New Haven-Springfield Interstate Air Quality Control Region where the violations of the annual primary National Ambient Air Quality Standard (NAAQS) for total suspended particulates (TSP) were recorded during calendar years 1977, 1978, and 1979. After public notice and a public hearing, EPA has determined that HWPC has made the necessary showing under section 113(d)(5)(D) of the Act, 42 U.S.C. 7413(d)(5((D), that particulate emissions from coal burning will not significantly cause or contribute to primary NAAQS violations.

(11) The Administrator has determined that the emission limits, requirements respecting pollution characteristics of coal and other enforceable measures contained in the following Order are sufficient to assure that the burning of coal at Mt. Tom will not result in emissions which cause or contribute to concentrations of any air pollutant in excess of any primary NAAQS for such pollutant.

(12) The Administrator also has determined that the compliance schedule in the following order requires compliance with 310 CMR 7.02(8), 7.05(4) and 7.06(1) as expeditiously as practicable.

(13) Furthermore, the Administrator has determined that the Interim Requirements of the following Order require the best practicable systems of emission reduction to protect the public health and minimize noncompliance with 310 CMR 7.02(8), 7.05(4) and 7.06(1).

I. SIP Limitation

Under this Order, the Mt. Tom generating unit owned by Holyoke Water Power Company (HWPC) shall comply with the interim emissions limits, compliance schedules, and other enforceable requirements set forth in this Order. The emission limits contained in this Order are authorized only until HWPC can install the necessary pollution control equipment to achieve compliance with 310 CMR 7.02(8), 7.05(4) and 7.06(1) of the Massachusetts SIP while burning coal at Mt. Tom. The Order contains a compliance schedule which sets a final compliance date by which HWPC's Mt. Tom generating unit must achieve compliance with all requirements of the SIP.

II. Interim Requirements

EPA has determined that the following interim requirements ensure that burning coal at Mt. Tom will not cause or contribute to primary violations of the NAAQS for TSP:

A. (1) Prior to burning coal at Mt. Tom, HWPC shall refurbish the existing dust collector to its original design specifications and install four new transformer-rectifier sets, as specified in HWPC's May 21, 1981 submittal to EPA.

(2) Not later than 15 days before initial burning of coal, HWPC shall notify EPA of the expected date that the dust collectors shall be refurbished for the purpose of EPA's conducting an inspection.

B. (1) Prior to initial burning of coal at Mt. Tom, HWPC shall install a flue gas conditioning system to enhance the collection efficiency of its electrostatic precipitator.

(2) The flue gas conditioning system shall be fully operational prior to emission testing on the source as required in II(E)(2) of this Order.

C. Not later than 7 days before initial burning of coal at Mt. Tom, HWPC shall submit to EPA written notice of the date it intends to start burning coal in the unit.

D. (1) Notwithstanding the requirements of II(D)(2) of this Order, HWPC shall burn coal at Mt. Tom with an ash content not in excess of 10% by weight (as received basis) for each shipment received.

(2) Within 240 days after initial burning of coal at Mt. Tom under this Order, HWPC shall burn coal at Mt. Tom with an ash content not in excess of 9% by weight (dry basis) for each shipment received.

(3) Coal shall be sampled for ash content according to the requirments of IV(B)(1) of this Order.

E. (1) Upon initial burning of coal at Mt. Tom, HWPC shall not emit particulate matter at a rate in excess of 0.480 pounds per million Btu gross heat input.

(2) HWPC shall conduct a particulate emission test on the unit within 45 days of initial burning of coal, to demonstrate compliance with this emission limit.

F. (1) Within 30 days after initial coal burning at Mt. Tom, HWPC shall submit to EPA a preliminary plan to optimize particulate emission reduction from operating the flue gas conditioning system.

(2) In addition, HWPC shall submit to EPA monthly status reports on the implementation of this plan.

G. (1) Within 120 days after initial coal burning, HWPC shall submit to EPA a final plan to optimize particulate emission reduction from operating the flue gas conditioning system. Upon approval by EPA, this final plan shall become enforceable under this Order.

(2) Within 150 days after initial burning of coal, HWPC shall conduct a particulate test on the unit in accordance with IV(A)(3) of this Order to demonstrate optimization of the flue gas conditioning system.

H. (1) Within 240 days after initial burning of coal at Mt. Tom under this Order, particulate emissions from the unit shall not exceed 0.350 pounds per million Btu gross heat input.

(2) HWPC shall conduct a particulate emission test on the unit within 240 days after initial burning of coal at Mt. Tom to demonstrate compliance with this emission limit.

I. Within 30 days after completing each set of particulate emission tests required by II(E) and (H) above, HWPC shall submit to EPA a report which correlates visible emissions as determined by EPA Method 9 (40 CFR Part 60, Appendix A) as a function of particulate emissions from coal burning.

(1) Each report shall propose an enforceable visible emissions opacity limit for the unit.

(2) EPA shall set an opacity limit for enforcement under this Order within 30 days of receipt of each report. EPA may require HWPC to submit additional visible emissions data under IV(A)(5) of this Order, and may use the additional data to revise opacity limits applicable to coal burning under this Order.

(3) Each report also shall propose an opacity monitor reading which correlates with particulate emissions from coal burning.

(4) Within 30 days of receipt of each report, EPA shall set an opacity monitor reading which will be used as an indicator of continuous compliance with the emission limits of this Order.

J. Within 30 days of the effective date of this Order, HWPC shall submit for approval by EPA a detailed program for minimizing fugitive particulate emissions from coal and coal ash handling.

(1) This program shall include as a minimum, HWPC's commitment to install a telescoping dust chute at the discharge point of the coal pile loading conveyor prior to initial coal burning.

(2) This program, including an implementation schedule, shall become a fully enforceable term of the Order.

K. (1) Within 30 days of the effective date of this Order, HWPC shall submit to EPA a written plan detailing the specific activities it plans to conduct to meet the coal ash content requirement specified in II(D)(2) of this Order. The plan must also demonstrate that HWPC will not stockpile nonconforming coal for use after 240 days from the date of initial coal burning at Mt. Tom. Upon approval by EPA, this plan shall become enforceable under this Order.

(2) In addition, HWPC shall submit to EPA monthly status reports within 15 days of the end of each month on the implementation and results of this plan.

III. Compliance Schedule

A. HWPC shall comply as expeditiously as practicable with the requirements of 310 CMR 7.02(8) and 7.06(1) or any superceding Massachusetts regulations as approved by EPA. In no event, however, shall compliance be achieved later than the dates specified in the following compliance schedule:

(1) Not later than December 31, 1981, HWPC shall enter into contracts for the design, fabrication, and installation of particulate emission controls or other equipment which is necessary for the unit to achieve final compliance with 310 CMR 7.02(8) and 7.06(1) or any superceding Massachusetts regulations as approved by EPA prior to this date.

(2) Not later than January 31, 1983, HWPC shall initiate on-site construction for installation of the continuous particulate emission control systems.

(3) Not later than December 31, 1983, HWPC shall complete the installation of the continuous particulate emission control systems.

(4) Not later than February 15, 1984, or within 45 days of completing installation of the continuous particulate emission control systems, HWPC shall perform particulate emission tests to demonstrate compliance with 310 CMR 7.02(8) and 7.06(1) or such superceding Massachusetts regulations as approved by EPA.

B. HWPC shall submit to EPA, no later than 15 days after each calendar quarter, calendar quarterly reports which outline its progress in meeting all the compliance milestones listed above. The first such report is due April 15, 1982.

C. In the event HWPC is unable to comply with any of the schedule increments established in III(A) above, and such failure is due to an Act of God, war, strike, or other such causes beyond its control, HWPC may petition EPA to extend the time for compliance with such schedule increment and all subsequent schedule increments by a period equal to the delay caused by such circumstances. HWPC shall bear the burden of proving that a delay is caused by circumstances clearly beyond its control. Any delay that is caused by such circumstances shall not be deemed a violation of this Order. In no event, however, shall final compliance be achieved later than December 31, 1985.

IV. Monitoring and Reporting Requirements

A. Emissions Monitoring and Reporting Requirements

1. All particulate emission testing shall be conducted in accordance with Reference Method 5, 40 CFR Part 60, Appendix A, under operating conditions approved by EPA and in the presence of EPA personnel or EPA representatives.

(a) HWPC shall provide safe access to a safe sampling platform on the unit to be tested.

(b) For the purposes of this Order, a particulate emission test shall consist of four Method 5 sampling runs. One of the four runs shall be conducted during the normal boiler sootblowing cycle, and three runs shall be conducted without sootblowing.

(c) The average emission rate for a particulate emission test shall consist of the arithmetic average of the three non-sootblow runs prorated in a manner specified by EPA to account for the change in emission encountered during the sootblow run.

2. For any emission or performance specification testing under this Order:

(a) HWPC shall submit a pretest report to EPA at least 30 days before the proposed test date for the unit.

(b) No fewer than 5 days before HWPC conducts any such test, EPA shall meet with appropriate HWPC personnel and any representatives of the contractor responsible for the performance of the tests to discuss and finalize the testing protocol.

(c) HWPC shall submit a written emission test report to EPA within 30 days of completing any EPA required emission testing.

(d) Pretest reports and emission test reports shall contain information as required by EPA and shall be presented in a format specified by EPA.

3. Within 150 days of initial burning of coal at Mt. Tom, HWPC shall perform emission tests on the unit as equipped with flue gas conditioning as follows:

(a) Two sets of tests shall be performed on the unit; one set while the flue gas conditioning system is operating, and one set while it is not operating.

(b) Each set of tests shall include:

(i) One particulate emission test of four runs conducted in accordance with EPA Method 5, 40 CFR Part 60, Appendix A.

(ii) At least 8 acid sulfate measurements in accordance with a method specified by EPA.

(iii) At least 8 sulfur dioxide measurements using EPA Method 6, 40 CFR Part 60, Appendix A.

(c) All acid sulfate and sulfur dioxide measurements shall be made during the approximate duration of the particulate testing.

(d) Each acid sulfate measurement shall be performed simultaneously with a sulfur dioxide measurement.

(e) The same type of coal shall be burned during both sets of tests.

(f) The boiler load, sootblowing operations and the amount of excess air shall be the same for both sets of tests.

(g) Both sets of tests shall be made while the unit and its electrostatic precipitator are operating under normal operating conditions.

(h) For any set of tests performed with flue gas conditioning, the flue gas conditioning system shall be operated in a manner specified by EPA.

(i) The tests with conditioning agents shall be preceded by at least 10 days of operation with conditioning agents to allow the precipitator to stabilize. Similarly, the tests without conditioning agents shall be preceded by at least 10 days of precipitator operation without conditioning agents.

(j) Each set of tests also shall be subject to the requirements of IV(A)(2) of this Order.

(k) If the approximate composition or usage rate of the conditioning agent changes at any time during the life of this Order, HWPC shall notify EPA in writing within 15 days of the change. If such change occurs after HWPC has performed the testing detailed above, EPA may require additional tests. If EPA decides to require such additional tests, HWPC shall be notified in writing. HWPC shall perform the additional tests within 30 days of receipt of the written notice.

4. HWPC shall install and operate continuous opacity monitoring equipment before burning coal in the unit.

(a) HWPC shall demonstrate that its opacity monitors comply with performance specifications within 30 days after initial burning of coal at Mt. Tom. HWPC shall comply with the provisions of 40 CFR Part 51, Appendix P, and the performance specification test requirements cross-referenced under 40 CFR Part 60, Appendix B. If two or more opacity monitors are used to report opacity from the boiler, HWPC shall submit to EPA for approval, an acceptable method for correlating each monitor to the total opacity at the stack outlet. HWPC shall notify EPA 10 days before removing any monitor from its location. This notification also shall include data which demonstrates that the new location for the monitor or its replacement meets the requirements of 40 CFR Part 60, Appendix B. Additionally, the monitor or its replacement shall be completely recertified according to 40 CFR Part 60, Appendix B before it is reinstalled. Data demonstrating recertification shall be provided to EPA upon request.

(b) Not later than 30 days prior to initial start-up of the continuous opacity monitoring equipment, HWPC shall submit to EPA an approvable quality assurance program for the monitoring system.

(c) HWPC shall report to EPA on a monthly basis in a format approved by EPA, all hourly average opacity readings for each opacity monitor which exceed the limits set by EPA under II (I) of this Order. These summary reports shall be submitted to EPA within 15 days of the end of each month; records of all hourly average opacity readings shall be retained at Mt. Tom for inspection for the duration of this Order. An explanation, if known, shall accompany each opacity exceedance.

B. Coal Monitoring and Reporting Requirements

Within 30 days of the effective date of this Order, HWPC shall submit an approvable fuel monitoring plan to EPA. As a minimum, such plan shall include a commitment on the part of HWPC to do the following:

1. HWPC shall perform proximate analyses of all coal cargoes off-loaded at Mt. Tom.

(a) ASTM D 3172 shall be used for the performance of the proximate analyses.

(b) ASTM D 2234 sampling with systematic spacing shall be used for sample increment collection.

2. HWPC shall perform daily coal sampling and analyses for sulfur content, ash content, and gross calorific value for coal burned under this Order.

(a) ASTM D 2234 sampling with systematic spacing shall be used for sample increment collection.

(b) Table 2 of paragraph 7.1.5.2 of ASTM D 2234 shall be used to determine the minimum number of increments and the minimum weight of each increment. Such increments from all conveyors are to be composited for analysis on a daily basis.

(c) ASTM D 2103 shall be used for sample preparation.

(d) ASTM D 3177 shall be used for sulfur analysis.

(e) ASTM D 3174 shall be used for ash analysis.

(f) ASTM D 3173 shall be used for moisture analysis.

(g) ASTM D 3160 shall be used for calculating analyses on either a dry or as received basis.

(h) ASTM D 2015 or ASTM D 3286 shall be used for gross calorific value determinations.

3. HWPC shall participate in the EPA coal analysis methods audit program conducted by the Quality Assurance Division, Environmental Monitoring Systems Laboratory in Research Triangle Park, North Carolina. Coal audit samples shall be analyzed according to ASTM procedures for percent sulfur, moisture, ash content and gross calorific value and will be provided by EPA on a periodic basis.

4. Monthly reports containing coal cargo shipment sizes, coal cargo analyses, and daily coal analyses shall be submitted to EPA within 15 days of the close of each month in a format approved by EPA.

(a) Such reports also shall contain 30-day "rolling average" sulfur content values for the coal burned calculated for each day of the month.

(b) The results of any audit coal sample analyses performed during that month also shall be included.

(c) All coal analysis data will be presented on a dry basis.

5. HWPC shall submit to EPA on a monthly basis hourly average net megawatts generated for the unit. Monthly data shall be reported within 15 days of the end of each month in a format approved by EPA.

6. HWPC shall perform any additional testing required by EPA within 30 days of receipt of written notification of such requirement. Among other things, additional testing may be required to quantify changes in emissions due to such factors as changes in coal characteristics, or changes in boiler or precipitator operation.

Additional tests also may be required to quantify suspected changes in emissions indicated by frequent opacity exceedences. Any proposal made by HWPC to limit total station emissions by derating the generating unit may result in additional testing requirements for the unit at any proposed generation levels.

7. HWPC shall maintain a logbook available for inspection by EPA containing the following data for the electrostatic precipitator:

(a) HWPC shall log secondary voltage, secondary current, and spark rate every 4 hours while the unit is burning coal.

(b) HWPC shall log voltage current relationships across the transformer-rectifier set's operating range every 15 days for the first 60 days after initial burning of coal in the unit. Thereafter, the data shall be logged every 30 days for the duration of this Order.

C. Ambient Monitoring and Reporting Requirements

1. (a) Within 60 days of the effective date of this Order but in no case later than the start of coal burning and subject to the provisions of IV(C)(5) of this Order, HWPC shall install and operate a network of ambient monitors to measure sulfur dioxide (SO_2) concentration on a continuous basis, and TSP concentration on a frequency as specified in IV(C)(2) below.

(b) As a minimum, HWPC shall place monitors for the following pollutants near each of the locations specified below:

(i) Summit House, Skinner State Park bordering Hadley and South Hadley: TSP and SO_2.

(ii) Mt. Tom Range, approximately 0.6 km southwest of Summit House approximately 750 feet above mean sea level, bordering Hadley and South Hadley: SO_2. TSP will be required only if the SO_2 levels exeed the secondary NAAQS.

(iii) Northampton area, Northampton: TSP. SO_2 will be required only if the TSP levels exceed the secondary NAAQS.

(iv) Pine Street, South Hadley: TSP and SO_2.

(v) Mt. Tom ski area, Holyoke: SO_2.

(vi) Goat Peak, Mt. Tom Range, Holyoke: TSP and SO_2.

(vii) Mt. Tom coal pile (to measure fugitive impacts), Holyoke: TSP.

(viii) Mt. Tom stackbase, Holyoke: SO_2.

(c) The burning of coal at Mt. Tom under this Order constitutes acceptance by HWPC that ambient monitoring data collected on its property is representative of ambient air quality levels in the surrounding area. EPA may use this data for enforcement or any other purpose as such under the Act.

2. The sampling frequency at the Northampton and Pine Street TSP sites shall be once every three days. The sampling frequency at all the remaining TSP sites shall be daily; however, the sampling frequency at a TSP monitoring site may be reduced to once every three days if the following conditions are met at such site during any continuous 365 days period after coal has been burned at Mt. Tom:

(a) Every 24-hour TSP concentration measured at the site must be less than 200 micrograms per cubic meter, and;

(b) The annual geometric mean of TSP measured at the site must be less than 60 micrograms per cubic meter.

3. All ambient monitoring locations and equipment installations must be approved by EPA prior to operation and must meet 40 CFR Part 58, Appendix B (Quality Assurance), Appendix C (Ambient Air Quality Monitoring Methodology), and Appendix E (Probe Siting Criteria).

(a) All SO_2 analyzers are to be operated on the 0.5 ppm range unless ambient air quality levels exceed this concentration. If this case occurs, then any such instrument must be operated on the appropriate higher range.

(b) Within 30 days of the effective date of this Order, HWPC shall submit in writing to EPA an approvable quality control program.

(c) EPA will accept performance audits by the Massachusetts Department of Environmental Quality Engineering (DEQE) to satisfy the requirements for the quarterly accuracy audit (40 CFR Part 58, Appendix B, Section 3), but it will be HWPC's responsibility to provide independent performance audits for any calendar quarter not audited by DEQE.

4. Within 60 days of initial burning of coal, HWPC shall complete construction of two 10 meter meteorological towers and one 100 meter tower at Summit House, Goat Peak, and near Mt. Tom's stack, respectively, for the purpose of operating continuous monitoring instruments to measure wind speed and direction.

(a) The exact location of these towers shall be selected by HWPC and shall be approved by EPA in writing before the towers are constructed.

(b) All meteorological instrumentation shall comply with EPA requirements as specified in EPA Guideline 450/4-80-012.

(c) All meteorological monitoring procedures must be submitted to EPA for approval at least 30 days before they are implemented.

5. HWPC shall obtain all the necessary permits, easements or permissions necessary to locate the monitors and meteorological towers required by IV(C) (1) and (4) of this Order. EPA may grant time extensions for monitor siting, select alternative sites, or eliminate sites altogether. However, HWPC bears the burden of establishing that all reasonable efforts have been made to locate the monitors and towers at the sites specified in this Order and that a change in the sites is necessary.

6. HWPC shall receive permission in writing from EPA prior to conducting any further analysis of the TSP filters. HWPC must keep all TSP filters in a suitable condition for further analysis for a period of 12 months after termination of this Order. HWPC must supply any of these filters to EPA upon request for further analysis. If the Federal Reference method for total suspended particulates is modified or replaced during the period of this order, EPA reserves the right to require HWPC to modify or replace any or all existing particulate monitors.

7. All monitoring and meteorological data shall be submitted to DEQE within 30 days of the close of each month in machine readable SAROAD format.

(a) The data reported to DEQE will be for individual hourly observations of SO_2, wind speed, and direction, as well as daily averages for TSP.

(b) HWPC shall insure that EPA receives the above information within 90 days of the end of each calendar quarter.

(c) HWPC shall notify EPA of any exceedence to any Primary National Ambient Air Quality Standard within 48 hours of receiving such data.

(d) Within 30 days of the close of each month, HWPC shall submit to both EPA and the DEQE, Springfield Regional Office, one paper copy of all monitoring and meteorological data. This data will be maintained for public inspection at the EPA Regional Office, Boston, and the DEQE Regional Office, Springfield, during normal working hours.

(e) EPA may grant time extensions to the data reporting requirements for this section, but HWPC shall bear the burden of establishing that such extensions are necessary.

8. Within 30 days of the occurrence of any violation of the primary National Primary Ambient Air Quality Standard for total suspended particulates, HWPC shall submit to EPA, all relevant data under Section 113(d)(5)(D) (i) through (iii) of the Act.

V. General Requirements

A. This Order shall not be effective during any interval after EPA finds and notifies HWPC that (1) a National Primary Ambient Air Quality Standard for total suspended particulates is being exceeded in the Hartford-New Haven-Springfield Interstate AQCR and (2) HWPC has failed to prove that the requirements of Sections 113(d)(5)(D) (i) through (iii) of the Act have been satisfied. During any such intervals, HWPC shall comply with 310 CMR 7.02(8), 7.05(4), and 7.06(1) or any superseding Massachusetts regulations as approved by EPA. If HWPC violates these regulations, it shall be subject to enforcement action under Section 113 of the Act.

B. Nothing herein shall affect the responsibility of HWPC to comply with any other applicable local, state or federal regulations.

C. HWPC shall submit a copy of all correspondence and reports required under this Order to the Director, Air and Waste Management Division, EPA, Region I, JFK Federal Building, Boston, MA 02203.

HWPC may assert a business confidentiality claim covering part or all of the information requested by this Order in the manner described by 40 CFR Part 2, Section 203(b). Information covered by such a claim will be disclosed by EPA only as set forth in 40 CFR Part 2, Subpart B. If no such claim accompanies the information when it is received by EPA, it may be made available to the public by EPA without further notice to HWPC. Certain categories of information are not properly the subject of such a claim.

For example, the Act provides that emission data shall in all cases be made available to the public. See 42 U.S.C. 7414(c).

D. HWPC is hereby notified that its failure to achieve final compliance at Mt. Tom with 310 CMR 7.02(8) and 7.06(1) by the final compliance date specified in III(A)(4) of this Order may result in an assessment of a noncompliance penalty under Section 120 of the Act, 42 U.S.C. 7240. This penalty may be imposed at an earlier date, as provided under Section 113(d) and Section 120 of the Act, in the event that this Order is terminated or violated as provided in V (E) and (F) below. In either event, HWPC will be formally notified of its noncompliance, under Section 120(b)(3) of the Act or any regulations promulgated thereunder.

E. This Order shall be terminated in accordance with Section 113(d)(8) of the Act if the Administrator determines, on the record, after notice and opportunity for hearing, that the inability of HWPC to comply with 310 CMR 7.02(8) and 7.06 as approved by EPA, no longer exists with respect to its Mt. Tom generating unit. Additionally, if HWPC demonstrates compliance with 310 CMR 7.02(8) and 7.06 prior to the final compliance date specified in III(A)(4) of this Order, then this Order shall be terminated at that earlier date.

F. Violation of any requirement of this Order shall result in one or more of the following actions:

1. Enforcement of such requirement under Section 113 (a), (b), or (c) of the Act, 42 U.S.C. 7413 (a), (b), or (c);
2. Revocation of this Order, after notice and opportunity for a public hearing;
3. Notification of noncompliance and assessment of a noncompliance penalty under Section 120 of the Act, 42 U.S.C. 7420.

G. The information requests contained in this DCO are not subject to the approval requirements of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.*

H. This order is effective November 24, 1981 and after having received concurrence from the Governor of the Commonwealth of Massachusetts.

Dated: November 17, 1981.

Anne M. Gorsuch,

Administrator, Environmental Protection Agency.

Delayed Compliance Order—Mt. Tom Generating Station Waiver of Rights To Challenge Order

Holyoke Water Power Company (the "Company"), by the duly authorized undersigned, hereby consents to the findings made and to the terms of this Order and waives any andall rights under provision of law to challenge this Order; however, the Company expressly reserves the right to assert any defense or to seek such other relief (other than an appeal from the issuance of this Order and the findings contained therein) as may be available to the Company in any enforcement action or other action taken pursuant to this Order or otherwise.

Dated: October 27, 1981.

Walter F. Torrance, Jr.,

Senior Vice President.

[FR Doc. 81-33085 Filed 11-23-81; 8:45 am]
BILLING CODE 6560-38-M

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40 CFR Part 60

[A-7-FRL 1967-2]

Adjustment of Opacity Standard for Fossil Fuel Fired Steam Generator

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: On August 18, 1981, there was published in the Federal Register (46 FR 41817) a notice of proposed rulemaking setting forth a proposed EPA adjustment of the opacity standard for Omaha Public District (OPPD), Nebraska City Power Station, Nebraska City, Nebraska. The proposal was based on a demonstration by OPPD of the conditions that entitle it to such an adjustment under 40 CFR 60.11(e). Interested persons were given thirty days in which to submit comments on the proposed rulemaking.

One written comment was received after the close of the comment period from OPPD pointing out in the proposal that the fourth paragraph under Supplementary Information referred to sixteen performance tests conducted from February 25, 1981 to April 16, 1981, as the basis for the EPA determination. This was incomplete information. The performance tests were conducted on January 20, 21, 22, 1981. In addition OPPD submitted data on sixteen opacity/mass correlation tests conducted from February 25, 1981, to April 16, 1981. All of this data was the basis for the EPA determination. There were three requests for copies of the background data. All test data on all tests was provided the requesters.

Since the omission was of additional testing which in fact enhances the EPA determination, and there were no comments other than from the source itself, there appears to be nothing of a substantive nature which would require the delay of repromulgation. The proposed adjustment is approved without change and is set forth below.

EFFECTIVE DATE: November 24, 1981.

FOR FURTHER INFORMATION CONTACT: Anthony P. Wayne, telephone 816-374-7130, or Henry F. Rompage, telephone 816-374-7152, Enforcement Division, EPA, Region VII, 324 E. 11th Street, Kansas City, Missouri 64106.

STATE IMPLEMENTATION PLAN REVISION

EPA has carefully evaluated the technical study submitted by Monongahela Power. The study has tentatively (pending public comment) been found to be a satisfactory demonstration of the need for a 253 meter stack under the current regulation and in accordance with EPA's "Guideline for Fluid Modeling of Atmospheric Diffusion" (EPA-600/8-81-009) and "Guideline for Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations)" (EPA-450/4-80-023). The former (highly technical) reference may be obtained from EPA's Environmental Sciences Research Laboratory and the latter general guideline from the Office of Air Quality Planning and Standards, both in Research Triangle Park, N.C. 27711.

Interested persons are invited to request a public hearing at which they will be afforded an opportunity to submit evidence on the technical adequacy of the fluid modeling demonstration. Because there is no proposed change in the emission limitation, there will be no testimony on that subject. If a hearing is held, it will be limited to the technical adequacy of the fluid modeling demonstration. The availability of the study and procedure for requesting a public hearing are given at the beginning of this notice.

Dated: May 19, 1982

Peter N. Bibko,

Regional Administrator.

[FR Doc. 82-15637 Filed 6-8-82; 8:45 am]

BILLING CODE 6560-50-M

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40 CFR Part 52

[A-1-FRL-2127-8]

Approval and Promulgation of Implementation Plans; Mount Tom Power Plant, Holyoke, Mass.; Revision to Particulate Emission Limit

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is approving a revision to the Massachusetts State Implementation Plan (SIP) which was submitted on January 22, 1982 by the Commissioner of the Massachusetts Department of Environmental Quality Engineering. The revision being approved today revises the allowable emission rate of particulate matter at the Mount Tom Power Plant, Holyoke, Massachusetts, from 0.12 pounds to 0.08 pounds of particulate matter per million Btu heat input. The effect of this revision is to allow the Mount Tom Power Plant to burn coal without jeopardizing the attainment or maintenance of air quality standards.

DATES: This action will be effective August 9, 1982, unless notice is received within 30 days that someone wishes to submit adverse or critical comments.

ADDRESSES: Written comments should be addressed to Linda Murphy, Acting Chief, State Programs Branch, EPA Region I (see address below). Copies of the Massachusetts submittal and EPA's evaluation are available for public inspection during normal business hours at the Environmental Protection Agency, Region I, Air Branch, Room 1903, JFK Federal Building, Boston, Massachusetts 02203; Public Information Reference Unit, Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; Office of the Federal Register, 1100 L Street, N.W. Room 8401, Washington, D.C., and Department of Environmental Quality Engineering, Division of Air Quality Control, 1 Winter Street, Boston, Massachusetts 02108.

FOR FURTHER INFORMATION CONTACT: Margaret McDonough, Air Branch, EPA Region I, Room 1903, JFK Federal Building, Boston, Massachusetts, 02203, (617) 223-4448.

SUPPLEMENTARY INFORMATION: On January 22, 1982 the Commissioner of the Massachusetts Department of Environmental Quality Engineering (the Massachusetts Department) submitted a request for approval of a revision to Regulation 7.17 "Conversions to Coal" which specifies conditions under which Holyoke Water Power Company's Mount Tom Power Plant is allowed to burn coal. This revision which EPA is today approving, specifies that upon conversion to coal, the Mount Tom Plant must (1) comply with the requirements of Regulation 7.05(1) "Sulfur Content of Fuels and Control Thereof" and (2) comply with a particulate emission limit of 0.08 pounds per million Btu heat input. Regulation 7.05 limits the sulfur-in-fuel content at Mount Tom to 1.21 pounds per million Btu heat release potential; no change is being made to this regulation. The particulate emission limitation is being decreased from 0.12 pounds to 0.08 pounds of particulate per million Btu heat input. Compliance with the new particulate emission limit will be determined through stack testing.

Since the only effect of this revision is to make the particulate emission limit more stringent, there is no adverse effect on air quality.

On November 24, 1981 (45 FR 57491) EPA issued a Delayed Compliance Order (DCO) for the Mount Tom plant which allows noncompliance with the Massachusetts SIP particulate emission regulation from November 24, 1981 to no later than February 5, 1984. Therefore, the revision to the particulate emission limit being approved today will not be enforced while the DCO is in effect.

Since this SIP revision changes the allowable particulate emission rate at the Mount Tom Power Plant to a more stringent limit, this rulemaking is considered noncontroversial, and no adverse or critical comments are expected. Therefore, this SIP revision is being published as a final rulemaking without going through proposed rulemaking. EPA believes that publishing a proposed rulemaking is unnecessary.

However, if notice is received within 30 days of the date of publication of this Federal Register notice that someone wishes to submit adverse or critical comments, this action will be withdrawn and two subsequent notices will be published before the effective date. One notice will withdraw the final action and another will begin a new rulemaking by announcing a proposal of the action establishing a comment period. If no such comments are received, the public is advised that this action will be effective August 9, 1982.

Pursuant to the provisions of 5 U.S.C. Section 605(b) the Administrator has certified that SIP approvals under Section 110 and 172 of the Clean Air Act will not have a significant economic impact on a substantial number of small entities. 46 FR 8709 (January 27, 1981). The attached rule constitutes a SIP revision approval under the January 27, 1981 certification. This action approves only state actions. It imposes no new requirements. In addition, this action only applies to one facility.

The Office of Management and Budget has exempted this rule from the requirements of Section 3 of Executive Order 12291.

Under Section 307 (b)(1) of the Clean Air Act judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by August 9, 1982. This action may not be challenged later in proceedings to enforce its requirements. (See Sec. 307(b)(2).)

After evaluation of the State's submittal, the Administrator has determined that the Massachusetts revision meets the requirements of the Clean Air Act and 40 CFR Part 51. Accordingly, this revision is approved as a revision to the Massachusetts State Implementation Plan.

List of Subjects in 40 CFR Part 52

Air pollution control, Ozone, Sulfur oxides, Nitrogen dioxide, Lead, Particulate matter, Carbon monoxide, Hydrocarbons.

(Sec. 110(a) and Sec. 301(a), Clean Air Act, as amended (42 U.S.C. 7410(a) and 7601 (a)))

Note.—Incorporation by reference of the State Implementation Plan for the State of Massachusetts was approved by the Director of the Federal Register on July 1, 1981.

Dated: June 2, 1982.

Anne M. Gorsuch,

Administrator.

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

Part 52 of Chapter 1, Title 40 of the Code of Federal Regulations is amended as follows:

Subchapter W—Massachusetts

Section 52.1120 is amended by adding paragraph (c)(49) as follows:

§ 52.1120 Identification of plan.

* * * * *

(c) * * *

(49) A revision to Regulation 7.17 "Conversions to Coal" submitted by the Commissioner of the Massachusetts Department of Environmental Quality Engineering on January 22, 1982 specifying the conditions under which coal may be burned at the Holyoke Water Power Company, Mount Tom Plant, Holyoke, Massachusetts.

[FR Doc. 82-15800 Filed 6-8-82; 8:45 am]

BILLING CODE 6560-50-M

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40 CFR Part 52

[A-5-FRL 2114-8]

Approval and Promulgation of State Implementation Plans; Illinois

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: On June 29, 1981 (46 FR 33334), the Environmental Protection Agency (EPA) proposed to approve a revision to the Illinois State Implementation Plan (SIP) for total suspended particulate (TSP) for the Caterpillar Tractor Company (Caterpillar). This revision grants nine Caterpillar boilers variance from Illinois Pollution Control Board (IPCB) Rules 203(g)(1)(A), Rule 203(g)(1)(C)(i), and/or Rule 203(g)(1)(D) which regulate particulate emissions from new and existing sources. In the June 29, 1981, Notice of Proposed Rulemaking, interested persons were given until July 29, 1981, to comment. On July 30, 1981, public comment period was extended to August 28, 1981, (46 FR 38937). The purpose of this notice is to discuss the public comment received and to announce EPA's final rulemaking action approving this proposed revision to the Illinois SIP.

EFFECTIVE DATE: This final rulemaking becomes effective July 9, 1982.

ADDRESS: Copies of the proposed SIP revision, the public comments received on the Notice of Proposed Rulemaking (45 FR 59597), and response to the comments are available at the following addresses:

U.S. Environmental Protection Agency, Air Programs Branch, Region V, 230 Dearborn Street, Chicago, Illinois 60604

The Office of the Federal Register, 1100 L Street NW., Room 8401, Washington, D.C. 20408.

FOR FURTHER INFORMATION CONTACT: Randolph O. Cano, Regulatory Analysis Section, Air Programs Branch, Region V, U.S. Environmental Protection Agency, 230 South Dearborn Street, Chicago, Illinois 60604, (312) 886-6035.

SUPPLEMENTARY INFORMATION: On November 29, 1979, Caterpillar obtained a variance from IPCB Rule 203(g)(1) for particulate emissions for thirteen coal-fired industrial boilers equipped with flue gas desulfurization systems, (FGD) at its East Peoria, Joliet, Mossville, and Mapleton, Illinois plants. The variance, in the form of a final order (Order) was amended on January 24, 1980 and on February 7, 1980. On April 4, 1980, the State of Illinois submitted the Order to EPA as a revision to the Illinois SIP. On June 29, 1981, EPA proposed rulemaking action on the submittal. The purpose of this notice is to discuss the public comments received and to announce EPA's Final Rulemaking action on approving this revision to the Illinois SIP.

On September 5, 1979, Caterpillar filed four Petitions for Variance from Rule 203(g)(1) for particulate emissions from thirteen boilers at its East Peoria, Joliet, Mapleton and Mossville, Illinois plants. These petitions were filed while the IPCB was considering a broader Caterpillar regulatory petition, R79-11 which sought the adoption of a particulate emission limitation of .025 lbs/MMBTU for all coal-fired industrial boilers equipped with FGD systems. On November 29, 1979, as amended on January 24, 1980 and February 7, 1980, the IPCB granted Caterpillar a variance from Rule 203(g)(1) until December 31, 1982, or until final rulemaking is completed on regulatory proceeding R79-11 for the sources listed in the accompanying table:

Facility	County	Attainment status	Boiler	Present regulation	Present emission limit in lbs/MMBTU	Proposed variance in lbs/MBTU
East Peoria	Tazewell	Primary nonattainment	19	Rule 203(g)(1)(C)(i)	0.1556	.25
			20	Rule 203(g)(1)(C)(i)	0.1556	.25
			21	Rule 203(g)(1)(D)	0.1	.32
			22	Rule 203(g)(1)(D)	0.1	.32
Joliet	Will	Primary nonattainment	2	Rule 203(g)(1)(A)	0.1	.25
			3	Rule 203(g)(1)(A)	0.1	.28
Mossville	Peoria	Secondary nonattainment	4	Rule 203(g)(1)(D)	0.1	.25
			5		0.1	.27
Mapleton	Peoria	Secondary nonattainment	1	Rule 203(g)(1)(D)	0.1	.26

The present emission limits and proposed variances in the above table were not similarly listed in the table contained in the Notice of Proposed Rulemaking. In that notice, both the present limit and the proposed variance were listed under the heading "Present Emission Limit" instead of being listed in two columns. Since all the information needed to interpret the table was presented, EPA is announcing its final rulemaking today without reproposal.

This variance covering the boilers at four Caterpillar Tractor Company

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DEPARTMENT OF ENERGY
WASHINGTON, D.C. 20585

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